Government of the Province of Alberta

THE PETROLEUM AND NATURAL GAS CONSERVATION BOARD

Interim Report with respect to applications now before the Board for permission to remove gas or cause it to be removed from the Province under the provisions of The Gas Resources Preservation Act.

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Printed in Canada

Price $1.00

1951

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I INTRODUCTION

The Petroleum and Natural Gas Conservation Board has before it at the present time applications for permits under The Gas Resources Preservation Act made by the companies listed in Appendix I to this report. Notice of the time and place of the hearings has been given in each case by extensive newspaper publications and by individual notice to each member of the Provincial Legislature.

Considerable progress has been made in the hearings of the applications as reflected in Appendix I which indicates the dates of the applications, the dates of hearings on each and the factors upon which evidence was presented at the hearings. All dates for hearings and adjournments thereof were fixed after consultation with the applicants and the other interested parties and dates were arranged to suit their convenience. The hearing of evidence commenced on January 30th, 1950, when Westcoast Transmission Company Limited commenced the presentation of its case.

On September 25th, 1950, at the opening of the hearing of the application of Western Pipe Lines, the Chairman read the following letters which had been received by the Board:

1. Letter dated August 29th, 1950, from Messrs. Milner, Steer, Dyde, Poirier, Martland & Layton, solicitors for Western Pipe Lines (Appendix 2) which was in the form of a notice of motion, due notice of which had been given to all applicants and other interested parties.

The letter stated that the Company was somewhat concerned over the amount of time which had been devoted to the presentation and cross-examination of evidence dealing with pipe line routes, design and cost. They pointed out that, while the Board required this evidence, none the less the Board of Transport Commissioners has to authorize the route and construction of any inter-provincial pipe line. They suggested that the Board curtail the presentation and the cross-examination of evidence on routes, pipe line design and cost, and further that the Board after hearing all pertinent evidence should determine the existence or otherwise, of an exportable surplus and if there should be a surplus, determine, with the approval of the Government, the conditions and provisoes necessary to protect the interests of the people of Alberta and of Canada. The choice of the pipe line route would then be left to the Board of Transport Commissioners.

The letter further suggested that the Board and the Government, having determined the conditions under which an export permit could be issued, could let it be known that such a permit would issue after the Board of Transport Commissioners had approved the route and after the Department of Trade and Commerce had licensed the export of natural gas if it is to go outside Canada.

Their letter also suggested that the Board consider the desirability of conducting a joint hearing in respect of all applications before it with regard to the question of the existence or otherwise of an exportable surplus of natural gas.

2. Letter from the Western Canada Petroleum Association dated September 20th, 1950, (Appendix 3) informing the Board of the following resolution adopted by the Association: "That The Petroleum and Natural Gas Conservation Board be requested to come to a decision at the earliest possible date as to whether the gas requirements of Alberta and the reserves of the Province are such as to warrant the export of natural gas; and that in order to expedite such decision, they confine their enquiries for the present to these questions only."

3. Letter from the Honourable N. E. Tanner, Minister of Mines and Minerals (Appendix 4) enclosing a copy of a letter he had received from the Right Honourable C. D. Howe (Appendix 5) and stating inter alia:

"Owing to the urgency expressed therein, I have been directed by the Executive Council to ask that your Board do all possible to facilitate your hearings so as to determine the amount of proven reserves of deliverable natural gas within the Province and the foreseeable needs of the Province for domestic and industrial use; and further, to advise as to whether or not and to what extent there is a surplus which might be available for sale outside the Province."

After hearing argument on the notice of motion and discussions on the other letters referred to, the Chairman made the following statement on behalf of the Board:

"The Board is prepared to hold a joint hearing on October 30th, 1950, for the purpose of hearing evidence, or further evidence, of all applicants and any interested parties in regard to reserves, deliverability and the requirements of the Province. It is our hope that all interested parties will take advantage of the joint hearing to see that the Board is provided with the fullest information on reserves, deliverability and Provincial requirements. We would like to stress that this information should embrace the following:

. . . We are not prepared at this time to make a statement with respect to the point raised by Mr. Martland relating to choice of routes being referred to the Board of Transport Commissioners. Should the disposition of applications be decided without reference to the Board of Transport Commissioners, the Board at the request of any applicant will hear any further evidence the applicant may wish to present with respect to any matter relating to other than reserves, deliverability and Provincial requirements. In the meantime any applicant should file such evidence with the Board."

The Joint Hearing commenced on October 30th, 1950, and lasted until November 10th. Evidence was heard only on the questions of reserves of natural gas in the Province, the requirements of gas within the Province, and deliverability of gas from sources within the Province. With the exception of Canadian Delhi Oil Limited all those with applications pending before the Board were represented at the hearing, that is:

Westcoast Transmission Company Limited (Canadian and Provincial Companies)
Northwest Natural Gas Company and Alberta Natural Gas Grid Limited
Western Pipe Lines
Prairie Pipe Lines Limited (Pacific Northwest Pipeline Corporation)
McColl-Frontenac Oil Company Limited and Union Oil Company of California

In addition to the evidence submitted by the applicants briefs were presented by:

The Research Council of Alberta
The Alberta Power Commission
Canadian Western Natural Gas Co. and Northwestern Utilities Limited
Imperial Oil Limited
Canadian Gulf Oil Company
Alberta Inter-Field Gas Lines Limited
Seaboard Oil Company of Delaware

Mr. G. E. G. Liesemer, Engineer of The Petroleum and Natural Gas Conservation Board, and Mr. M. B. Crockford, Geologist of The Petroleum and Natural Gas Conservation Board, presented independent briefs on the reserves and geology of the Province.

At the conclusion of the hearing, the Chairman made the following statement on behalf of the Board in regard to the motion to leave the choice of route to the Board of Transport Commissioners:

> "The Board is not presently ready to decide or even comment on the suggested reference to the Board of Transport Commissioners and will not be able to do so until it has had further opportunity to consider the evidence submitted at this joint hearing.
>
> "Should the Board require evidence on matters other than those dealt with in this joint hearing, from applicants who have not as yet had an opportunity of submitting such evidence, all parties registered before the Board as interested will be notified accordingly and an opportunity thus given for both direct and cross-examination on such other matters."

This report is an interim report and contains the present opinions of this Board concerning the matters referred to in the Honourable Mr. Tanner's letter.

II GEOLOGY AND NATURAL GAS RESERVES OF THE PROVINCE

In making an appraisal of gas reserves a general knowledge of the geology is essential. In its study of evidence submitted at the various hearings, the Board has reviewed each estimate of gas reserves keeping in mind the overall geological conditions. In many instances the Board's experience and general knowledge of the geology derived from its own records of the gas development of the Province has influenced its decision with respect to reserve estimates submitted by the applicant.

Some excellent geological reviews of Alberta's potential oil and gas bearing deposits were submitted by G. O. G. Sanderson, S. E. Slipper and M. B. Crockford at the various hearings. Other geologists also outlined briefly the succession of sedimentary deposits which form the reservoir rock containing oil and gas accumulation in this Province.

The following summary of the sedimentary geology of the Province was prepared in order to outline briefly the various factors which control the accumulation of gas deposits.

Geology

During geological time all or part of Alberta was subjected to invasions of the sea during which marine sediments were deposited. Frequent emergence of the land mass above sea level at the end of the Paleozoic era and during subsequent periods resulted in the erosion of much of the Paleozoic rock and re-disposition of fresh water and brackish water deposits sandwiched in between deposits laid down during later marine invasions. As a result, partly of long periods of erosion and partly of extended periods of unequal deposition of sediments, the sedimentary deposits overlying the Pre-Cambrian rocks in Alberta vary greatly in thickness.

In the northeastern part of the Province the Pre-Cambrian rocks are exposed at the surface. The thin wedge of Paleozoic sediments overlying the Pre-Cambrian starts in the vicinity of Lake Athabasca and thickens toward the west and southwest until those sediments attain a thickness of several thousands of feet in the foothills belt lying in front of the Rocky Mountain ranges. This wedging out of the Paleozoic to the northeast was chiefly caused by erosion at the end of the Paleozoic era and as a result we find successively younger beds present at the top of the Paleozoic as we progress to the southwest.

The beds of the Mesozoic period were laid down on the eroded surface of the Paleozoic and in the McMurray district the Cenozoic sediments overlie rocks well down in the Paleozoic series. Wells drilled in the western and southwestern parts of the Province penetrate great thicknesses of the upper Paleozoic beds before reaching rocks of the same age as those which directly underlie the Cenozoic at McMurray. The Paleozoic sediments, as far as known, are all of marine origin. They consist chiefly of shales, limestones and dolomite. They are not as a rule good reservoir rock for the accumulation of gas owing to the scarcity of porous beds. There are, however, some excellent porous beds present in the rocks of Devonian age particularly where the skeletons of reef building organisms have accumulated in sufficient thickness and areal extent to form a suitable reservoir for accumulation and retention of fluids. Our largest oil pools such as Leduc and Redwater occur in such beds.

Some porous beds also occur in the limestone and dolomitic rocks of the Rundle formation of Mississippian age. This formation is not known to occur in the northeastern and central eastern part of the Province. Our largest gas reserves such as Pincher Creek, Turner Valley and Jumping Pound occur in the Rundle formation. Owing to the great thickness of sediments overlying the Paleozoic in the western part of the Province coupled with the intricate structural conditions in the foothills belt, development and prospect drilling in that area has been very slow. Drilling depths approximate 10,000 feet to test the top of the Paleozoic in the outer foothills and in the area immediately adjacent to the east, and even greater depths are required to reach the deeply buried Devonian beds. Owing to the difficult drilling conditions and high cost of sinking the deep prospect wells very few have penetrated the full succession of Paleozoic beds in that part of the Province. The excellent prospect of further discoveries of large reserves of gas in the foothills and adjacent areas has been discussed by Mr. S. E. Slipper and others in their submissions to the Board and

the Board fully concurs with the suggestion that further prospect drilling in that part of the Province would be most desirable.

Sediments of Cenozoic age which include the Triassic, Jurassic and Cretaceous rocks consist predominently of shales and sandstone of both marine and continental origin. The marine sediments are composed almost entirely of shale. Limestone beds are rare and such sandstone as occurs as marine deposits are, as a rule, thin and composed of very fine sand grains resulting in low permeability for the movement of fluids through them.

The continental or fresh water deposits also consist mostly of shale but are not laid down as continuous sheets over an extensive area. They are distributed in an irregular crazy quilt pattern, overlapping and interspersed with patches or lenses of variable grades of sediments from fine shale to coarse sands and even conglomerates.

Intermediate deposits, partly marine and partly continental also occur. Some of these were no doubt deposited in bays and estuaries on the edge of the sea and in shallow waters near the shore line. Such deposits may contain fossils of marine organisms but, as a result of off shore currents, wave action and currents from the continental rivers emptying into the sea, have been laid down in an irregular pattern with rapid transition from well sorted sands to shale and all grades between. Sandstone beds of marine origin have, to date proved to be the most extensive gas reservoirs in the Cenozoic rocks of Alberta.

Deposits of the Triassic period are the oldest of the Cenozoic rocks. These are known to occur only in the western and northwestern part of the Province and were recently a source of an interesting discovery by wells drilled at Whitelaw and Bluesky. This area has been mentioned as a large potential reserve by some geologists at the Joint Hearing but requires further drilling for evaluation.

The next oldest rocks of the Cenozoic era are those of the Jurassic period. They occur in the western and southern part of the Province and are also of marine origin. The Fernie or Ellis formation produces some gas in Southern Alberta from sandstone reservoirs but has not proven important as a source of gas to date. However, since some sandstone beds are known to occur in the formation and since it occurs chiefly along the western side of the Province where relatively few wells have been drilled it may yet prove an important source of gas.

Formations of the lower part of the Cretaceous are mostly continental with some beds of marine and brackish water in the lower part. Rocks of this period extend over most of Alberta. Gas has been discovered in many wells drilled through these sediments in practically all parts of the Province where drilling has been carried out. The most frequent discoveries have been in the marine and brackish water deposits of the basal formations. Some of the geologists submitted substantial estimates of gas reserves based on these discoveries. Others discounted them as not having been sufficiently developed to base an estimate or have ruled them out almost entirely as being too costly to develop owing to the erratic distribution of the sands and to the small reserve which could be expected from any one pool. There was a particularly large variance in the estimates submitted for the Lower Cretaceous of the Morinville area. Mr. Crockford in his submission illustrated the erratic occurrence of sands in the Basal Cretaceous by presenting logs of the wells drilled in the Excelsior oil field which is situated close to the discovery gas well of the Morinville area. The danger of assigning a large block of acreage to a Lower Cretaceous discovery well for the purpose of a gas reserve estimate has recently been demonstrated by the drilling of a dry hole well within the area used by one geologist in his reserve estimate. From evidence submitted and from opinions obtained by cross-examination of witnesses at hearings, the Board considers it prudent to discount to a considerable extent any large reserve estimation in the Lower Cretaceous based on undeveloped acreage. From past experience in this Province it has been found that, where attempts were made to develop reserves of both oil and gas, the Lower Cretaceous has proved unreliable. The percentage of dry holes which present experience indicates would be required to develop these reserves makes their development for other than local use seem questionable. The Board has no doubt that in the aggregate the Lower Cretaceous sediments contain a large reserve of gas, and there is always the possibility of finding large pools, but none have been developed to date.

Several sandy zones occur in the marine formations of the Upper Cretaceous. Sands near the base of the Alberta formation of Colorado age form the reservoir for such gas fields as Viking-Kinsella, Bow Island, Pendant d'Oreille and Manyberries. These sands, although widely distributed, are in most places

where drilling has been carried out, mixed with shale and are non-porous or are too thin to form a gas reservoir of economic importance. Where structural conditions are suitable, large reserves have accumulated in these sands and they form some of the Province's important gas reserves.

Many wells have discovered gas in this horizon in other parts of the Province but further development is needed before any reliable estimate can be made of the reserve.

A local occurrence of sand near the top of the Colorado forms the reservoir for the Medicine Hat gas reserve. This sand has apparently only local distribution in that area as it has not been discovered by wells drilled elsewhere in the Province.

Some estimates were submitted of gas reserves of the Milk River formation which overlies the Colorado. Thin beds of fine sand in this formation have a wide distribution over southern Alberta. They form an important source of artesian water over a considerable area and many of these water wells also produce sufficient gas for farm use. This gas reserve is considered important only as a source of supply for local use on farms and for small utility systems.

No sediments above the Colorado have yielded any gas of commercial importance to date in this Province.

In summarizing the situation with respect to the sedimentary geology of the Province there are many rock formations of wide distribution which are known to be favorable for the collection and retention of oil and gas deposits. Such formations occur in rocks of the following eras:

Paleozoic—Devonian
Mississippian (Rundle)

Cenozoic—Triassic
Jurassic (Ellis or Fernie)
Cretaceous (marine and fresh water beds of the Lower Cretaceous)
Marine sands in the Upper Cretaceous.

As previously suggested, probably the most attractive possibilities for the development of further large reserves of gas at high pressures are in the foothills and adjacent areas to the east. One must not lose sight, however, of the fact that comparatively little drilling has yet been done in the Province as a whole and what has been done was chiefly for the discovery and development of oil. Practically all of our presently known gas reserves were discovered while drilling for oil and very little attempt has been made to prospect for and develop gas reserves beyond the immediate needs of the presently established utility systems.

Mr. J. O. Lewis, a geologist with some fifty years' experience in the United States gave a very interesting comparison between the geologically promising areas in Alberta and in Texas. While the areas are approximately the same, up to the beginning of 1950, 273,453 wells had been drilled in Texas as opposed to 2,914 in Alberta. He pointed out that reserves of both oil and gas still are being discovered at a faster rate than old reserves are being depleted. Texas oil reserves as at the end of 1949 were $12\frac{1}{2}$ billion barrels and gas reserves were 99 trillion cubic feet, both up from 1948. Gas production in 1949 was $3\frac{1}{2}$ trillion cubic feet. He was impressed by the amount of Alberta gas reserves proved up with a comparatively small number of wells and while Alberta could not expect to have reserves as large as Texas because formations underlying Alberta do not have as much gas capacity per square mile as in Texas, he considered the reserves so far discovered a minor fraction of what may be discovered in the future.

Geologists who had made detailed studies of the petroliferous strata underlying the Province varied in their opinion as to what particular geological formation or formations might prove the most promising source of gas reserves but all were of the opinion, and the Board concurs, that vast reserves of gas can be discovered with an extensive drilling programme.

Natural Gas Reserves

In its review of the gas reserve estimates submitted at the various hearings, the Board found many widely divergent opinions with respect to reserves in individual fields. In most instances the engineers and geologists followed the same methods of calculation but some of the factors used differed to such an extent that the end results in some cases varied by as much as tenfold. All gas reserve estimates were ex-

pressed in standard cubic feet at a pressure base of 14.4 pounds per square inch and at a temperature of 60° Fahrenheit.

Methods of Estimating Reserves

Two methods are available for the estimation of the magnitude of reserves of gas in the ground—these are the pressure-decline or material balance method and the volumetric or porosity-area method. Engineers and geologists testifying before the Board employed one or other of these methods depending upon the circumstances. While the pressure-decline method is ordinarily considered the more reliable, it is important to know the characteristics and limitations of both methods.

Pressure-Decline Method

For application of the pressure-decline method of calculation, sufficient gas must have been produced from the reservoir to cause a substantial decline in the reservoir pressure. (Since only a few fields in the Province meet these conditions the pressure-decline method was not employed in many cases.) If the volume of gas produced and the decline in pressure caused by the removal of the gas are known, the gas remaining in the reservoir at any given pressure can be calculated.

The pressure-decline method, however, has definite limitations. Even where sufficient gas has been produced to cause a substantial decline in the reservoir pressure, water encroaching on the edges or bottom of the reservoir may have taken up some of the space formerly occupied by gas and the observed decline in reservoir pressure in that event will be less than would normally take place if there had been no water encroachment. A reserve estimate based on a pressure-decline calculation under these circumstances would be too high.

The observed decline in pressure can also give misleading information in reservoirs of low permeability. In such fields the movement of gas is slow and the most heavily produced sections of the field will register a greater decline in pressure than parts which have had less gas withdrawn. Under these circumstances, a stabilized pressure is never obtained for the reservoir and caution must be exercised in seeing that a weighted average pressure is used in the reserve calculation. The weighted average pressure cannot be obtained with accuracy, however, in fields such as Medicine Hat where the field has not been fully developed. The pressure-decline method of calculation is applicable only to fields having a relatively old production history, and since the accuracy of early records of production and the initial reservoir pressure are frequently in doubt the full benefit of this method of estimating reserves is not always attained.

Porosity-Area Method

In the porosity-area method of calculation an estimate must be made of the void space in the reservoir rock which is occupied by gas. In order to make the calculation the following controlling factors must be known or estimated:

(1) the average porosity of the reservoir rock (usually expressed as percentage);
(2) the proportion of the void space occupied by liquids;
(3) the average thickness of the producing section;
(4) the areal extent of the reservoir.

From these data the volume of void space in the reservoir that is occupied by gas is calculated. A calculation is then made of the amount of gas at standard conditions that can occupy that space at reservoir conditions of pressure and temperature. The accuracy of this method of calculation depends upon the amount and the reliability of the factual data available.

A controlling factor, and the one which caused the greatest variation in the estimates based on the porosity-area method of calculation, is that of acreage. Since most of the gas reserves in the Province, of which estimates were submitted, are only partially developed, the area over which a reserve extends is unknown. The value placed on the acreage factor for any particular reserve can, therefore, only be a judgment figure unless the area has been completely delineated by drilled wells. In certain cases, however, where reliable geophysical surveys have been made, information so obtained assists in predicting the extent of the productive area. The Board feels that in some instances the acreage factor applied to the formula used in estimating reserves reflected exceptional optimism on the part of the person making the calculation.

There was a considerable variation of opinion as to the thickness of the productive zone in some fields on which estimates of reserves were submitted. This was rather surprising to the Board particu-

larly where drilled wells had provided data on this matter by means of cores, and electrologs. As with the acreage factor, the thickness factor used in the formula in calculating reserves is a multiplying factor and any variation in its magnitude is reflected directly in the end result.

In the case of most of the other factors involved the variation of opinion was not large although in individual cases there was disagreement concerning porosity and connate water.

Reservoir Loss

Since it is economically impossible to produce all of the gas in a reservoir, some discount has to be made from the estimate of gas in place to arrive at the amount which will be produced before the reservoir pressure is reduced to the point where the field is no longer economical to operate. This discount reflects the unavoidable reservoir loss. The reservoir abandonment pressure depends upon several factors, chief of these being the depth of wells, the cost of operation and the value of the gas. The reservoir pressure normally increases in proportion to the depth at which the reservoir occurs below the surface. A high pressure reservoir may produce a greater percentage of its initial gas than one of low pressure but it cannot be economically drawn down to as low a pressure before its is abandoned, owing to the greater friction effect and the greater weight of the column of gas in the deeper wells. As a result, at equivalent pressures at the well-head, the pressure in the deeper reservoir is greater than that in the shallower. The reservoir loss can, and usually does, exceed that calculated on the basis of an assumed abandonment pressure. This is particularly the case with thin sands underlain by water where irregular water encroachment can isolate portions of the reserve from the producing wells.

During cross-examination at the joint hearing, Mr. R. E. Davis described a study which he has been carrying out of abandoned gas fields in order to determine the percentage recovery that can be expected from new fields based on the record of these depleted fields. Although Mr. Davis did not consider that his investigation had been carried sufficiently far to base any definite conclusions, it did indicate that the discount factors used in some of the estimates presented were too low.

Surface Loss

After arriving at an estimate of the producible gas to an abandonment reservoir pressure, other discounts must be applied to arrive at the amount of gas that can be made available for market. These discounts, which reflect an unavoidable surface loss, include, where applicable: operational loss, gas for gas lift operations, lease fuel, drilling fuel, line heater fuel, loss by flaring of oil field gas not economically gatherable, processing plant fuel, shrinkage due to the removal of carbon dioxide, hydrogen sulphide, water vapor, natural gasoline and other hydrocarbons. The amount of these discounts depends on operating conditions and on the physical characteristics of the gas. Gas from Viking-Kinsella field does not require processing except for the extraction of some water vapor and therefore only a small discount is required to take care of ordinary operating losses. Gas from Turner Valley, Jumping Pound and Pincher Creek requires treatment for the extraction of liquid hydrocarbons, hydrogen sulphide and carbon dioxide before it is suitable for market. The volume of gas available for market from these fields will, therefore, be considerably less than that which can be produced at the well.

A schematic representation of the reservoir and the surface loss in relation to gas in place, gas producible and marketable gas is given in Figure 1.

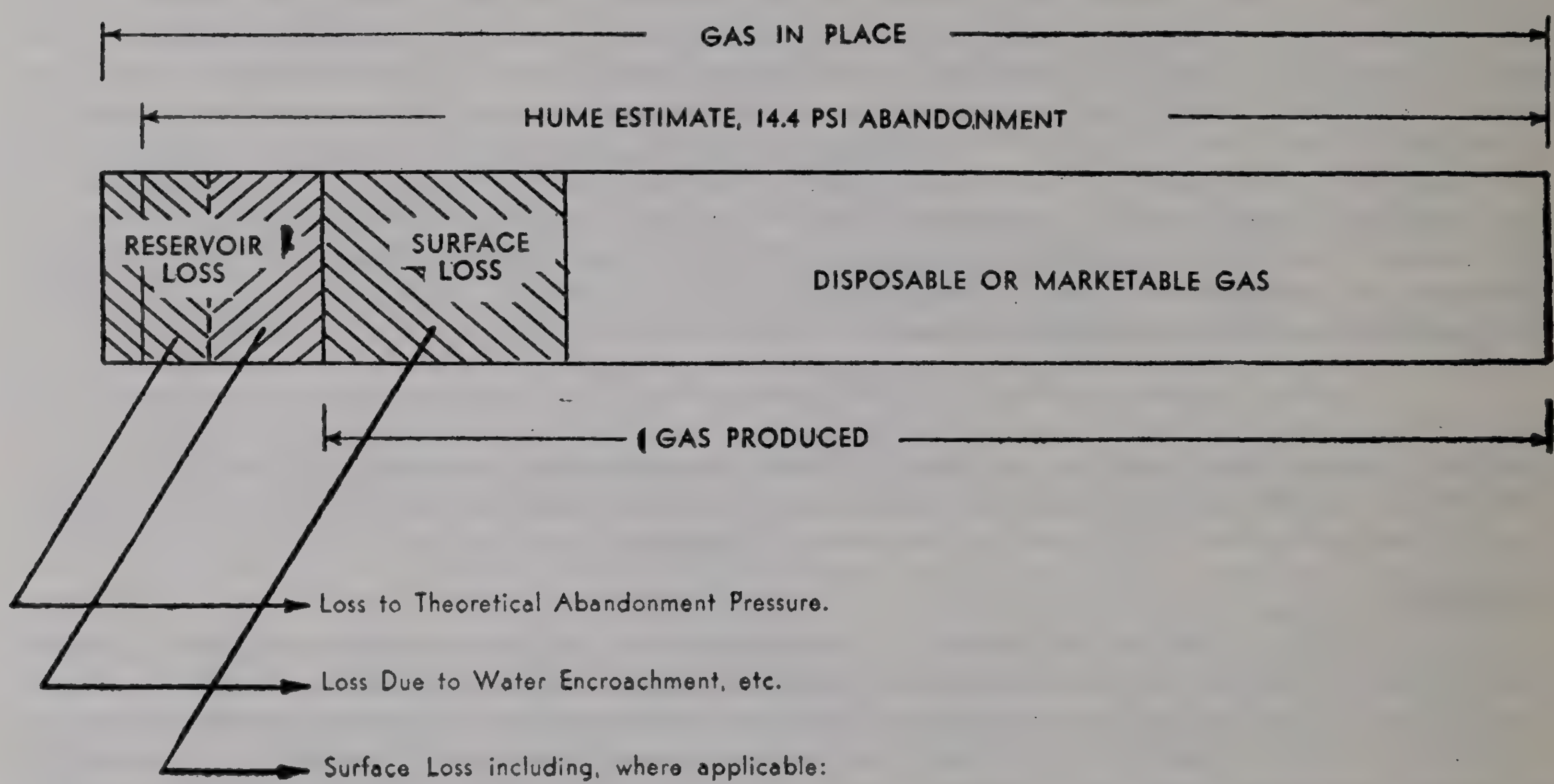
Hume and Ignatieff 1950 Report

During the hearings and in many of the submissions on gas reserve estimates, reference was made to the work of Dr. G. S. Hume and A. Ignatieff, "Natural Gas Reserves of Prairie Provinces" published in 1950 by the Department of Mines and Technical Surveys (commonly referred to as Hume's estimates). Dr. Hume's estimates are of gas to an abandonment pressure of 14.4 p.s.i. absolute—approximately equivalent to the "gas in place"—see Figure 1. He has made no attempt to estimate the amount of gas which might be made available to market. Both the porosity-area and the pressure-decline methods were employed—each where it was applicable.

Estimated reserves are given under the categories "proven" and "probable" with discussion and comment on "potential" reserves. In the "proven" group Hume includes such fields as Turner Valley, Viking-Kinsella, Medicine Hat, Leduc and several smaller fields which have been sufficiently developed to provide data for a reliable estimate. Among the "probable" reserves he classes the undeveloped fields such as Jumping Pound, Pincher Creek, the undeveloped part of Medicine Hat, Pendant d'Oreille and many

Figure 1

Schematic Representation of Reservoir and Surface Loss and the Relation Between Gas in Place and Marketable Gas



Operational loss—blowing for dewaxing, clearing water, loss during stop-cocking, loss during testing, etc.

Gas for lift operations—if not regatherable.

Lease fuel, drilling fuel, production heater fuel, etc.

Fuel for line heaters, etc.

Loss by flaring of oil well gas at wells which cannot economically be connected to a gathering system.

Compressor fuel.

Processing plant fuel.

Shrinkage due to removal of hydrogen sulphide and/or carbon dioxide.

Shrinkage due to removal of water vapor.

Shrinkage due to removal of natural gasoline and/or other hydrocarbons.

others. Hume's "potential" category includes all those gas strikes which have not been developed beyond the initial discovery stage and concerning which there is little data for estimating.

In connection with certain of the probable reserves, Hume assumed an area of 2,000 acres per well as a basis for a porosity-area estimate. He contends that while this figure may be high or low in an individual case, it will, on the average be realistic. The Board believes that such a figure may be satisfactory for use with sands which are consistent and reasonably continuous but, on the basis of experience in this Province, cannot accept it for sands such as the Lower Cretaceous, particularly when these sands are thin. In a lesser degree this also applies to the Viking.

Estimates of Applicants

Statements concerning the reserves of the Province were submitted by the Westcoast Transmission Company, the Northwest Natural Gas Company, Prairie Pipe Lines, Western Pipe Lines and McColl-Frontenac-Union Oil Company. Mr. Liesemer of the Conservation Board staff submitted an assessment of the reserves made independently of the applicants and the Board. Many of the individual field estimates presented by the various applicants were based on Hume's estimates of "gas in place" with adjustments and allowances for various factors including reservoir and surface loss.

In addition the Canadian Western Natural Gas Company Limited, the Northwestern Utilities Limited, Imperial Oil Limited and the Canadian Gulf Oil Company submitted independent reserve estimates of fields which were of particular interest to them.

The Board wished to present a detailed comparison of the estimates of gas reserves of the entire Province as submitted by each of the applicants. It was found impractical to do so, however, since all applicants did not submit estimates on a comparable basis. The following incomplete tabulation shows estimates of "disposable gas" compiled from those submitted. Two of the applicants presented estimates for only part of the Province and the number of fields included in the other estimates varied in all cases.

Estimates by	Disposable gas MMMcf
Westcoast Transmission Ref. Table A. Brief Dec. 1950	7,023 (1)
Northwest Natural Gas Company Ref. Brief Dec. 1950, Table following P. 8	5,006 (2)
Prairie Pipe Lines Ex. J-33, Joint Hearing	4,684 (3)
Western Pipe Lines Ex. No. 6 P. 30 and Tr. Vol. I Page 56 Hearing W.P.L.	5,614 (4)
McColl-Frontenac & Union Oil Co. Ex. J-11, Joint Hearing, Tab. No. 2	6,284 (5)
Liesemer Ex. J-41, Joint Hearing	3,635 (6)

(1) Includes 90 MMMcf beyond economic reach, entire Province.
(2) Eleven fields, excludes Medicine Hat and other local reserves.
(3) Nine fields of over 50 MMMcf each.
(4) Estimate for entire Province, includes reserves beyond economic reach.
(5) Includes 660 MMMcf beyond economic reach, entire Province.
(6) Includes 191 MMMcf beyond economic reach, entire Province, but excludes reserves less than 20 MMMcf and certain ones beyond economic reach.

As a comparison, the Board's estimate of reserves of disposable gas in the Province (including 219 MMMcf beyond economic reach and excluding certain small reserves of less than 5 MMMcf is 4,658 MMMcf.

Analysis of the Estimates

The Board feels that all engineers and geologists who submitted reserve estimates were sincere and endeavoured to provide the Board with all available information at hand. Owing, however, to the scarcity of factual data, in many instances they had to use a judgment figure for the chief factor in their calculation. Moreover the manner of classification of the reserves, i.e. whether "proven" or "probable," "possible" or "potential," is a most difficult problem and one concerning which there was a wide spread of opinion.

In its analyses of the gas reserve estimates, the Board has endeavoured to be realistic. It considers that if the present and future needs of the Province are to be adequately protected, there should be a reasonable expectancy that such gas reserves are available from presently known discoveries and that

the gas can be developed economically and made available for use when and as required. While all reserve calculations are necessarily estimates, some reflect a higher degree of reliability than others—depending upon the amount of factual data upon which the estimate is based. For such fields as Turner Valley, part of Viking-Kinsella and part of Medicine Hat which have a fairly long production history behind them reliable estimates can be expected. Estimates of reserves roughly outlined by widely scattered wells, such as in Pendant d'Oreille, or reserves in a well defined structure on which only a few wells have been drilled such as at Pincher Creek and Jumping Pound, are necessarily less reliable and must be most cautiously made. Estimates of reserves undeveloped beyond the initial discovery well are considered by the Board to be highly speculative unless they are based upon very conservative acreages.

With these points in mind the Board has considered all reserves from the viewpoint of whether or not, and to what extent, they could be considered as "established" in the sense that their existence and estimated amount could reasonably be counted upon. In the opinion of the Board only such "established reserves," properly discounted for reservoir and surface loss, warrant consideration for the protection of the present and future requirements of the Province.

Accordingly, the Board has studied and analyzed the voluminous evidence and arrived at its estimate of Established Reserves of Disposable Gas. In doing this the Board has not included isolated single well discoveries or reserves less than 5 MMMcf (unless they were close to a community). These reserves undoubtedly exist, but the amount of such reserves on an established basis is small and would not affect the overall picture. Moreover these occurrences either by virtue of presently known size or because of geographical remoteness could hardly be considered as available in an economic sense.

Details of the Board's estimate of the present Established Reserves of Disposable Gas are presented in Table I. The reserves are subdivided into three categories: Local Use, General Use, and Beyond Economic Reach of a market. In making these classifications distance from market was not the only factor considered. The size of the reserve, the cost of drilling wells and of gathering the gas and preparing it for transmission to market was considered as well as the cost of constructing a pipe line to carry the gas to a local market or to a major transmission line. Some substantial gas reserves of this Province can be regarded as beyond economic reach of a market even though a transmission pipe line may be constructed through the reserve because the gas cannot economically be made available to the line. On the other hand some reserves presently listed as beyond economic reach of a market can quite reasonably be expected to become within economic reach if further development is carried out.

Comments concerning certain of the fields follow Table I, as does a discussion of gas occurrences, including single well discoveries not referred to in the table.

Table I presents the basic data on which the Board made its estimate together with specific comments concerning the various estimates. Values for the basic factors were selected, after study, from data presented in evidence or in a few cases from the records of the Conservation Board. In this selection the Board has endeavoured to avoid both unsubstantiated optimism and unjustified pessimism. Greater weight has been given to the evidence of those witnesses which in the Board's opinion had the greater detailed knowledge in specific cases.

Referring to Table I—

Column	Presents
1	Name of field or best known well or wells.
2	Productive or potentially productive formation or zone.
3	Estimated areal extent of the productive sand.
4	Estimated average thickness of the productive sand.
5	Estimated average porosity of the productive sand.
6	Estimated average connate water content of the productive sand.
7	Reservoir temperature, Degrees Rankine=460+Degrees Fahrenheit.
8	Reservoir pressure, pounds per square inch absolute=pounds per square inch gauge+15 pounds per square inch.

9	Compressibility factor at reservoir conditions to account for deviation from ideal gas behaviour.
10	Estimated volume of gas in reservoir Jan. 1, 1951, expressed in terms of billions of cubic feet at standard conditions (14.4 p.s.i.a., 60° F). Estimate based upon factors 3 to 9 inclusive unless otherwise noted.
11	Estimated reservoir pressure at time of abandonment of field, pounds per square inch absolute.
12	Discount applicable to the "Gas in Place" figure (Column 10) to account for gas left in the reservoir at abandonment. In the case of thin sands this discount exceeds the theoretical amount.
13	Discount applicable after that for the reservoir loss, to account for surface loss. This factor includes (where applicable) allowances for gas flared, operational loss, field and/or plant fuel, and processing shrinkage attending the removal of carbon dioxide, hydrogen sulphide, propane and butanes plus.
14, 15, 16	Established reserves are reserves of disposable gas which in the opinion of the Board may be reasonably counted upon. The reserves are expressed in billions of cubic feet at standard conditions and are based upon the figures of Columns 10, 12 and 13.
14	Established reserves of marketable gas presently supplying local systems or considered logical sources of supply for such systems. Does not include reserves for the two major provincial distributing systems.
15	Established reserves of marketable gas available for general use including the supply for the two major provincial distribution systems.
16	Established reserves of gas which in the opinion of the Board are not within economic reach of a market either because of (a) size and location, or (b) gathering and processing difficulties, e.g. Redwater solution gas.
17	Comments of specific application to individual fields.

Summarizing the findings of the Board with respect to Established Reserves of Disposable Gas, the totals are:

	MMMcf
Local Use	382
General Use	4,057
Beyond Economic Reach	219
Total	4,658 MMMcf

Table 1

The Petroleum and Natural Gas Conservation Board

ESTABLISHED RESERVES OF NATURAL GAS IN THE PROVINCE OF ALBERTA, JANUARY 1, 1951

(Exclusive of Isolated Single Well Discoveries and Reserves Estimated at less than 5 MMMcf but including Reserves Supplying Local Systems)

(For explanation of column headings and other notes see bottom of 20)

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	1.	17.
											Discount Factors		Established Reserves				
FIELD	FORMATION	Area (Acres)	Pay Thickness (Feet)	Porosity (%)	Connate Water (%)	Reservoir Temperature (°R)	Reservoir Pressure (psia)	Comp. Factor (Fraction)	Estimated Gas in Place (MMMcf)	Abandonment Pressure (psia)	Reservoir (%)	Surface (%)	Local Use (MMMcf)	General Use (MMMcf)	Beyond Economic Reach (MMMcf)	FIELD	REMARKS
Athabasca	Lower Cretaceous	1800	20	20	20	518	522	0.91	10	100	19	10	7	--	--	Athabasca	This is a preliminary estimate only. The Conservation Board is planning a more detailed study.
Battleview-Vermilion													9	--	--	Battleview-Vermilion	This is a preliminary estimate only. The Conservation Board is planning a more detailed study.
Black Butte	Ribbon	2200	12	20(a)		550	1380	0.83	25	100	12(b)	10	--	20	--	Black Butte	
	Jurassic	2600	6	12(a)		554	1490	0.83	9	100	17(c)	10	--	6	--	Black Butte	
	Rundle	740	23	10(a)		555	1350	0.83	8	100	7	20	--	6	--	Black Butte	Surface loss higher than normal due to need for processing to remove hydrogen sulphide.
Bon Accord	Viking	2500	12	20	40	533	820	0.87	10	100	17(b)	10	--	7	--	Bon Accord	
Bonnyville													3	--	--	Bonnyville	This is a preliminary estimate only. The Conservation Board is planning a more detailed study.
Bow Island	Viking						618	0.90	19	100	16	5	--	15	--	Bow Island	Calculation by pressure-decline method. Field used as storage field in C.W.N.G. System.
Brooks	Milk River					521	325	0.93	7	100	31	10	5	--	--	Brooks	Calculation by pressure-decline method.
	Lower Cretaceous					551	1450	0.83	6	100	7	10	5	--	--	Brooks	Calculation by pressure-decline method.
Castor	Viking	2000	9	20	20	557	1000	0.87	9	100	20(c)	10	6	--	--	Castor	
	Lower Cretaceous	640	19	20	20	565	1150	0.87	7	100	9	10	6	--	--	Castor	
Dunmore	Bow Island	1920	7	15	30	540	1000	0.86	5	100	20(c)	10	--	4	--	Dunmore	May be beyond economic reach.
	Jurassic	5500	7	15	30	550	1500	0.84	20	100	17(c)	10	--	15	--	Dunmore	May be beyond economic reach.
Elk Point													5	--	--	Elk Point	This is a preliminary estimate only. The Conservation Board is planning a more detailed study.
Excelsior	Lower Cretaceous	1500	20	18	20	552	1200	0.82	18	100	8	10	--	15	--	Excelsior	Field now producing oil from the D-2 zone. Gas production from the Lower Cretaceous may be deferred until after recovery of the oil.
Foremost (Cal. Stand. Area)	Bow Island	15000	5	20	35	540	700	0.90	23	100	30(d)	10	--	15	--	Foremost	
Foremost	Bow Island					531	614	0.90	17	100	21(b)	10	--	12	--	Foremost	Calculation by pressure-decline method.
Golden Spike	D-3											15	--	24	--	Golden Spike	Oil Reserve calculation. Gas production rate dependent upon oil production. Economics of gathering is uncertain. Surface loss higher than normal due to need for processing.
Hanna	Rundle	1000	10	12(a)		553	1550	0.81	6	100	17(c)	10	4	--	--	Hanna	
	Lower Cretaceous	1000	10	18	20	555	1400	0.81	7	100	17(c)	10	5	--	--	Hanna	
Joseph Lake	Viking	2800	13	25	15	557	850	0.92	20	100	17(b)	10	--	15	--	Joseph Lake	Production of this gas will, in large part, be deferred until after the recovery of the underlying oil.
Jumping Pound	Rundle	5250	130	10(a)		620	4015	0.87	800	400(f)	10	25	--	540	--	Jumping Pound	Surface loss higher than normal due to need for processing. There are definite possibilities that further development may increase the established reserve by 100 to 150 MMMcf.
Lac la Biche	Pelican	2000	10	20	20	505	360	0.93	4	100	38(c)	10	--	--	2	Lac la Biche	
	Lower Cretaceous	2000	15	20	20	514	670	0.88	11	100	20(b)	10	--	--	8	Lac la Biche	
Leduc-Woodbend	D-2 Solution								165	250(f)	32	45	--	66	--	Leduc-Woodbend	Oil reserve calculation. Gas production rate dependent upon oil production. Surface loss higher than normal due to need for processing.
	D-3 Solution								340	115(f)	12	45	--	160	--	Leduc-Woodbend	Oil reserve calculation. Gas production rate dependent upon oil production. Surface loss higher than normal due to need for processing.
	D-3 Gas Cap								600	115(f)	6	20	--	450	--	Leduc-Woodbend	Production of this gas will, in large part, be deferred until after the recovery of the underlying oil. Surface loss higher than normal due to need for processing.
	Lower Cretaceous	3280	40	20	35	579	1401	0.82	79	200(f)	15	30	--	47	--	Leduc-Woodbend	Field now producing oil from D-2 and D-3 zones. Gas production from the Lower Cretaceous may be deferred until after recovery of the oil.
Legal	Viking	3000	9	14	40	533	786	0.88	6	100	23(c)	10	--	4	--	Legal	
Lloydminster													2	--	--	Lloydminster	This is a preliminary estimate only. The Conservation Board is now conducting a more detailed study.
Manyberries	Bow Island (Manyberries Sand)	15000	10	22	25	545	890	0.89	73	100	21(c)	10	--	52	--	Manyberries	
	Bow Island (Upper Sand)	2000	10	20	25	545	825	0.89	8	100	21(c)	10	--	6	--	Manyberries	

TABLE I CONTINUED

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	1.	17
											Discount Factors		Established Reserves				
FIELD	FORMATION	Area (Acres)	Pay Thickness (Feet)	Porosity (%)	Connate Water (%)	Reservoir Temperature (°R)	Reservoir Pressure (psia)	Comp. Factor (Fraction)	Estimated Gas-in Place (MMMcf)	Abandonment Pressure (psia)	Reservoir (%)	Surface (%)	Local Use (MMMcf.)	General Use (MMMcf.)	Beyond Economic Reach (MMMcf.)	FIELD	REMARKS
Medicine Hat	Medicine Hat Sand					518	456	0.92	522	100	32(c)	10	320	--	--	Medicine Hat	Calculation by pressure-decline method.
Morinville	Lower Cretaceous	4000	38	19	20	572	1135	0.87	83	100	9	10	--	68	--	Morinville	
Princess-Patricia	Colorado	10000	10	15	20	542	1245	0.83	52	100	18(c)	10	--	38	--	Princess-Patricia	
	Sunburst	7500	13	18	20	547	1545	0.81	77	100	11(b)	15	--	58	--	Princess-Patricia	Surface loss higher than normal due to presence of nitrogen and its effect in lowering the heating value.
	Jefferson	660	18	16	20	558	1470	0.83	7	150(f)	10	25	--	5	--	Princess-Patricia	Surface loss higher than normal due to presence of nitrogen and its effect in lowering the heating value.
Pelican-Wabiskaw	McMurray	5000	20	20	15	505	300	0.96	16	100	33	10	--	--	10	Pelican-Wabiskaw	
Pendant d'Oreille	Bow Island (5 sands)	83750	7.8	24	20.5	540	750	0.89	308	100	23(c)	10	--	213	..	Pendant d'Orielle	There are five producing sands present. Weighted average figures have been used in Columns 6-11 inclusive.
Picardville	Viking	1000	28	11	40	538	890	0.87	11	100	11	10	--	9	--	Picardville	
Pincher Creek	Rundle	17250	394	2.6	20	651	4945	0.94	1825	400(f)	9	30	--	1170	--	Pincher Creek	Surface loss higher than normal due to need for processing. There are definite possibilities that further development may increase the reserve by 100-200 MMMcf.
Pouce Coupe	Gates	12400	22	20	35	530	650	0.91	75	100	15	10	--	57	..	Pouce Coupe	An export permit has been issued covering 13 billion cubic feet of this reserve to supply the town of Dawson Creek, B.C.
Provost	Viking	23500	9.5	2.7	35	540	850	0.87	110	100	22(c)	10	--	78	--	Provost	
Redwater	D-3 Solution											50	--	--	50	Redwater	Tentative estimate. Oil reserve calculation. Gas production rate dependent upon oil production. Economics of gathering is uncertain. Surface loss higher than normal due to need for processing.
	Viking								3	100	25(c)	10	2	--	--	Redwater	This is a preliminary estimate only.
Smith Coulee	Bow Island	6700	8	22	25	540	750	0.90	22	100	23(c)	10	..	15	--	Smith Coulee	
Stettler	D-2 Solution											40	..	--	20	Stettler	Tentative estimate. Oil reserve calculation. Gas production rate dependent upon oil production. Economics of gathering uncertain.
	D-3 Solution											50	--	--	6	Stettler	Tentative estimate. Gas production rate dependent upon oil production. Economics of gathering uncertain.
St. Paul													3	--	--	St. Paul	This is a preliminary estimate only. The Conservation Board is planning a more detailed study.
Turner Valley	Rundle												--	300	--	Turner Valley	Gas cap and solution gas. Gas cap calculated by pressure-decline method. Solution gas calculated by pressure-decline, gas-oil ratio trends method. Surface loss higher than normal due to need for processing.
Viking-Kinsella	Viking					540	728	0.91	895	100	28(d)	10	--	582	--	Viking-Kinsella	Calculation by pressure-decline method.
Whitelaw-Bluesky	Whitelaw (Triassic)	1000	145	23	35	549	1420	0.81	109	100	7	10	--	--	{ 108	Whitelaw-Bluesky	
	Bluesky (4 sands)	640	51	25	35	549	1150	0.81	21	100	8	10	--	--		Whitelaw-Bluesky	
											TOTAL		382	4057	219		

EXPLANATION OF COLUMN HEADINGS

Column

1 Name of field or best known well or wells.
2 Productive or potentially productive formation or zone.
3 Estimated areal extent of the productive sand.
4 Estimated average thickness of the productive sand.
5 Estimated average porosity of the productive sand.
6 Estimated average connate water of the productive sand.
7 Reservoir temperature, Degrees Rankine=460+ Degrees Fahrenheit.
8 Reservoir pressure, pounds per square inch absolute=pounds per square inch gauge+15 pounds per square inch.
9 Compressibility factor at reservoir conditions to account for deviation from ideal gas behaviour.
10 Estimated volume of gas in reservoir Jan. 1, 1951 expressed in terms of billions of cubic feet at standard conditions (14.4 p.s.i.a., 60°F). Estimate based upon factors 3 to 9 inclusive unless otherwise noted.
11 Estimated reservoir pressure at time of abandonment of field, pounds per square inch absolute.
12 Discount applicable to the "Gas in Place" figure (Column 10) to account for gas left in the reservoir at abandonment. In the case of thin sands this discount exceeds the theoretical amount.
13 Discount applicable after that for the reservoir loss, to account for surface loss. This factor includes (where applicable) allowances for gas flared, operational loss, field and/or plant fuel, and processing shrinkage attending the removal of carbon dioxide, hydrogen sulphide, propane and butanes plus.
14, 15, 16 Established reserves are reserves of disposable gas which in the opinion of the Board may be reasonably counted upon. The reserves are expressed in billions of cubic feet at standard conditions and are based upon the figures of columns 10, 12 and 13.
14 Established reserves of marketable gas presently supplying local systems or considered logical sources of supply for such systems. Does not include reserves for the two major provincial distributing systems.
15 Established reserves of marketable gas available for general use including the supply for the two major provincial distribution systems.
16 Established reserves of gas which in the opinion of the Board are not within economic reach of a market either because of (a) size and location, or (b) gathering and processing difficulties. e.g. Redwater solution gas.
17 Comments of specific application to individual fields.

General Notes

Reference

(a) Gas saturated porosity—no deduction for connate water necessary.
(b) Theoretical discount plus 5%.
(c) Theoretical discount plus 10%.
(d) Theoretical discount plus 15%.
(f) High abandonment pressure, due to depth of zone and/or other factors.

As pointed out in the tabulation and referred to later, the Board is of the opinion that specific possibilities exist for an increase in the Established Reserves of Jumping Pound and Pincher Creek with further development of these fields. A tentative estimate of the increase which might be established is 100-150 MMMcf for Jumping Pound and 150-200 MMMcf for Pincher Creek.

Further Comment With Regard to Certain Fields

Certain fields seem to require comment beyond that which could be indicated in Table I. These remarks follow under a listing of the field heading.

Leduc --Woodbend

This field is presently supplying some of its gas production to the Northwest Utilities System and also provides gas for two local utilities which service Leduc, Calmar and Devon. The gas occurs in three different horizons and present supplies are all produced with oil.

The uppermost horizon occurs in Lower Cretaceous Sands and is believed to be associated with oil over a relatively small part of the area in which it is known to be present.

The second horizon occurs in the Devonian dolomitic limestone section commonly referred to as the D2 zone. The gas is in solution with crude oil and a free gas cap has been found at the top of the zone in only a few wells in the field. The absence of any active water drive to maintain reservoir pressure is expected to result in a low recovery of the oil and gas present in this zone.

The third horizon known as the D3 zone also occurs in the Devonian some distance below the D2 zone. Gas occurs in solution with the oil and as a free gas cap above the oil in the same reservoir. An active water drive is believed to be present and should be instrumental in the recovery of a large percentage of both oil and gas from the reservoir.

Separate reserve estimates were submitted to the Board for the Lower Cretaceous, the D2 solution gas, the D3 gas cap and the D3 solution gas. Most estimates for the original reserves in place were in fairly close agreement but there was some divergence of opinion as to the amounts that might be made available for market. All engineers agreed that there was little possibility of the Lower Cretaceous gas being produced until after the oil and gas in the D2 and D3 reservoirs were depleted since it will be more economical to use the oil wells later for producing Lower Cretaceous gas than to drill wells specifically for that purpose.

For its estimate of gas reserves in the Lower Cretaceous the Board accepted the estimate presented by Mr. Liesemer.

Estimates of gas in solution with the oil in the D2 and D3 zones were based on the gas-oil ratio of the estimated oil reserves of these two reservoirs. For an estimate of the marketable gas from the oil zones and from the D3 gas cap, the Board accepted the reserve estimate of Mr. Pot but made allowance for less surface loss than Mr. Pot suggested might be applicable for this gas when he appeared as a witness at the Joint Hearing.

Jumping Pound

This is a wet gas field lying on the outer folds of the foothills belt. Production is obtained from the Rundle formation of Paleozoic Age.

To date only three wells in this field have been completed as gas producers. One of these is near the edge of the structure and has only a thin producing section above the water table. The other two are thought to be on the crest of the structure. One well is being drilled and a location has been prepared for another. This structure was outlined by seismograph and is less than a mile in width in the part that has been developed by drilled wells and is not expected to be any wider in the undeveloped portions. Since the seismograph map of the structure proved reliable in the drilling of the producing wells, it is expected that the general outline of the field will follow fairly close to that predicted by the seismograph. There was, however, some disagreement as to the probable size of the field, and the Board in compiling an estimate of the reserve used an acreage of 5,250.

Differences of opinion also existed as to the thickness of the pay section and the porosity of the reservoir rock. Factual data was lacking in this regard as only fragmentary cores had been recover-

ed from the wells and the estimates were based for the most part on analysis of drill cuttings. Comparison with the Turner Valley limestone section was also used as a guide in estimating the porosity of the producing section by some of the engineers.

There was also difference of opinion as to the reservoir pressure. Since the Board could find no authentic information on any of these three factors it used an arbitrary figure for each within the range of those presented for its own estimate of the reserve. Although the estimate of gas reserves in this field as compiled by the Board is higher than five estimates presented at the hearings, it is probably slightly lower than the average of all estimates.

Medicine Hat

This field has the oldest development history of any gas reserve in the Province. Little is known regarding the character of the producing sand as very few cores have been taken from wells in the field. Development has extended over a large area and the limits of the field have not yet been determined. Until recent years production records have not been reliable and an estimate had to be made of production to date.

A number of estimates of gas reserves were submitted to the Board for this field, all of which were based on the pressure-decline method of calculation.

Since the sand permeability is low on the fringes of the field and thin gas-bearing sands are known to occur for some miles distant from the main reservoir, the producing sands of the field are no doubt continually being replenished to some extent from beyond the boundaries of the main producing area. Owing to the slow migration of gas in the reservoir and to the uncertain production record of the field, the reserve estimates made on a pressure-decline basis may not be reliable.

In reviewing the reserve estimates for the Medicine Hat field the Board accepted the estimate submitted at the Joint Hearing by Mr. G. E. G. Liesemer but deducted 10% for field and line loss as he did not appear to have made any discount for this item.

Pelican -- Wabiskaw

In the Pelican - Wabiskaw area of the northeastern part of the Province gas was first discovered in 1897 by the Dominion Government in a well drilled at the confluence of the Portage with the Athabasca River. Three wells have recently been drilled at widely spaced locations in the general area, and in each well substantial gas flows were encountered in the McMurray sand of the Lower Cretaceous. The McMurray sand appears fairly continuous where it is exposed on the river bank farther down stream and forms the well-known McMurray tar sands. The continuity of this sand bed over the entire area and beyond the known gas occurrences is a subject for conjecture.

Seaboard Oil Company of Delaware submitted an estimate at the Joint Hearing of 1,336 MMMcf. for the Wabiskaw area based on 200,000 acres as the areal extent of the reservoir. The Board considers that there are specific possibilities of a reserve in the area far beyond that given in Table I, but many more wells will have to be drilled before the potentiality of the area can be appraised. The gas occurs at shallow depths and the reservoir pressure is only about 300 pounds per square inch. The area is covered with muskeg and timber and is practically uninhabited. The cost of developing and gathering gas from this area will be very high. The low reservoir pressure and the consequent need for a great number of wells, many miles of gathering line, and field compressors, to obtain the required volume of gas for a transmission system would appear to place this field beyond economic reach of a market regardless of the size of the reserve.

Pendant d'Oreille

Gas in this field occurs in the Bow Island sand in the lower part of the Colorado formation.

Although the field has produced practically no gas to date, the outline of the producing area is believed to have been fairly well delineated by wells drilled by McColl-Frontenac Oil Company and Union Oil Company of California.

All estimates of gas reserves in this field were based on the porosity-area method of calculation.

In its compilation of gas reserves, the Board accepted the reserve estimate submitted by Dr. H. H. Beach, Chief Geologist for McColl-Frontenac Oil Company, since it was considered that he had access to more up-to-date information and was better acquainted with the geology of the field than other engineers.

In accepting Dr. Beach's estimate for gas in place, the Board applied a 23% discount to allow for reservoir losses, and 10% for loss in field operations as it was felt that Beach's discount for these items was too low. Past experience has shown that a discount of 10% to allow for loss in field operations is not too great for a field of this type where wells may be frequently blown down to unload water and to clean them out for efficient operation.

Pincher Creek

Like Jumping Pound, the Pincher Creek gas reserve occurs in a foothills structure which has been outlined by the seismograph. Production is from the Rundle formation. The area of the field is thought to be much larger than Jumping Pound and the reservoir pressure is considerably higher. Two wells about seven miles apart have been completed as gas producers and another was drilled sufficiently off structure that it penetrated the reservoir below the gas-water interface. A third well is presently being drilled. The producing wells are situated near either end of the structure as depicted by the seismograph and the drilling well is located between the two producers.

There is some indication of cross faulting through the central portion of the structure and the possibility of this faulting affecting the continuity of the productive zone throughout the length of the structure was discussed at some length during the cross-examination of the various witnesses at the hearings.

Canadian Gulf Oil Company has the entire structure under lease and that company submitted an estimate of the gas reserves at the Joint Hearing.

Since better core recovery was obtained from the wells on this structure than those at Jumping Pound and since more tests as to the well potentials were carried out, a considerable amount of factual data is available regarding the producing section penetrated by the wells.

It was brought out by cross-examination of witnesses at the hearings that some engineers were in doubt as to whether the information obtained from two wells spaced seven miles apart would represent the average for the field. In Turner Valley, where production is obtained from limestone of the same age, there is a wide variation in the productivity in various sections of the field and it appears reasonable to suppose that similar conditions occur in the Pincher Creek field.

The Board accepted the Gulf estimate of gross gas producible at an abandonment pressure of 400 p.s.i. but applied a discount factor of 30% in place of the company's estimate of 20% for plant shrinkage, field use and field waste and its further allowance for separator liquids. It was thought that the company's estimate was too conservative for a field of this type.

Princess -- Patricia

This area is difficult to define since it contains several small producing fields and in addition numerous isolated wells which have discovered gas. Some engineers submitted separate estimates for the reserves of Princess and of Patricia. There was some doubt as to the exact area on which some estimates were based and the Board found it difficult to make comparisons. The reserve picture is made even more confusing by the presence of three different gas producing horizons, none of which blanket the entire area. In order to avoid duplication, the Board reviewed all estimates presented as a compilation of reserves in the entire Princess - Patricia area.

Gas has been encountered in the basal part of the Colorado formation in the eastern part of the area in a few widely separated wells. The gas sand is of marine origin and may have a fairly wide distribution. Although this horizon has been penetrated in nearly all wells of the area, it was tested for gas in relatively few of them. In its estimate of the reserves of this horizon the Board has probably taken a conservative view in considering 38 MMMcf of gas can be made available for market.

The so-called Sunburst sand of the Lower Cretaceous produces both oil and gas in the area. It is a lenticular type of sand and found to be very erratic as to areal extent and thickness in any particular locality. On account of its very irregular distribution the estimates on its reserves of gas varied to a great

extent. The Board feels that it is optimistic in estimating 58 MMMcf of marketable gas for the Sunburst sand.

The Jefferson formation of the Devonian has yielded oil and gas in only a few wells in a very small area. Although many wells in the Princess-Patricia area have not been drilled to the Jefferson the Board could not see any justification for basing a reserve estimate on more than the 660 acres used by John Galloway in his estimate on behalf of Prairie Pipe Lines. The Board considers that the cost of developing any large gas supply from this field will be high owing to the large percentage of dry holes that may be expected and is doubtful if these reserves are within economic reach of a market.

Turner Valley

Many estimates have been made on the gas reserves of this field in past years. In 1945 in a hearing before the Natural Gas Utilities Board the various experts agreed on a gas reserve of 345.5 MMMcf. of marketable gas. The 1945 estimate less 91.4 MMMcf produced in the succeeding five years was submitted to this Board as an estimate of Turner Valley reserves by several engineers. Ralph E. Davis, appearing for the Canadian Western Natural Gas Company considered the 1945 estimate to be too low and estimates present reserves of marketable gas in this field at 350 MMMcf to the end of 1949. When consideration is given to the pressure decline in Turner Valley during the past six years, it appears that the 1945 estimate was conservative and the Board has arbitrarily decided on an amount of 300 MMMcf as a reserve of marketable gas still to be produced from this field as of January 1, 1951.

Viking -- Kinsella

This field has also had a relatively long production history which will permit an estimate of remaining reserves by the pressure-decline method. The characteristics of the producing sand are similar to that of the Medicine Hat field. The field is fairly well delineated but thin bands of gas bearing sand having low permeability may extend for many miles beyond the borders of the developed area.

There was a considerable degree of variation in some of the estimates of gas reserves for this field.

Dr. Nauss, appearing on behalf of Westcoast Transmission Company, submitted an estimate of 842 MMMcf of marketable reserves based on the porosity-area method of calculation. Other estimates based on this method of calculation were slightly lower.

Mr. Liesemer and Mr. Davis both submitted estimates based on the pressure - decline method. Liesemer's estimate of 609 MMMcf and Davis' estimate of 612.5 MMMcf of marketable gas were in close agreement.

The Board accepted Davis' estimate as it was considered that he had an intimate knowledge of that field, having acted as consultant for the Canadian Western Company for many years. The Board, however, deducted 2½% from Davis' estimate to allow for field waste during blow-downs and tests of wells and also deducted the gas produced during 1950 since Davis' estimate was for the end of 1949.

Whitelaw -- Bluesky

In the Whitelaw area in the northwestern part of the Province two wells situated over four miles apart have encountered gas in the Triassic and one of these also encountered gas in the Lower Cretaceous. A third well situated in line with the others and about six miles from the nearest has penetrated the zones which produced gas in the others but was non-productive. This well is still drilling at the date of this report. The Board considers that there are still good prospects of the gas reserve in this area being extended beyond that indicated in Table I.

Other Gas Occurrences

In addition to the reserves listed in Table I many other gas occurrences are known throughout the Province. Reserve estimates have been submitted to the Board for some of these while others were not mentioned during the hearings. The Board considers that the reserves as indicated for these occurrences are too small to affect the overall picture with respect to the provincial requirements or require further development to evaluate. Another factor is the questionable economics of gathering gas from small and/ or geographically remote reserves.

A list of the districts in which these gas discoveries have been made are set out in Table II No doubt many other wells have been drilled through gas bearing strata while drilling for oil.

TABLE 2

OTHER GAS OCCURRENCES

Locality	Productive Formation	Remarks
Ashmont-Spedden	Lower Cretaceous	
Barrhead	Rundle	
Barnwell-Taber	Lower Cretaceous	Small flows also in Colorado
Bassano	Lower Cretaceous and Rundle	Gas discovery in L.C. late 1950
Big Valley	Devonian	Gas with oil
Bon Accord	Colorado	
Boyle	Lower Cretaceous	
Brazeau	Lower Cretaceous and Rundle	Lower Cretaceous discovery in one well
Brandi	Devonian	One well Athabasca district
Camrose	Devonian	Gas with oil
Cessford	Basal Colorado and Lower Cretaceous	Several wells drilled in 1950
Claresholm	Lower Cretaceous	One well
Coronation	Lower Basal Cretaceous	
Chip Lake	Lower Cretaceous	One well
Deadhorse Coulee	Lower Cretaceous and Rundle	Lower Cretaceous gas depleted. Gas in Rundle high in hydrogen sulphide
Deadman	Viking	One well
Del Bonita	Rundle	Gas with oil
Drumheller-Delia	Lower Cretaceous	
Eagle Butte	Colorado	Gas with water
Edgerton	Lower Cretaceous	
Edmonton District	Lower Cretaceous	Discoveries in several wells in vicinity of city.
Jarvie	Colorado and Lower Cretaceous	
Many Islands Lake	Colorado	
Moose Mountain	Devonian	
Normandville	Lower Cretaceous	One well
Oyen-Cereal	Colorado and Base of Lower Cretaceous	
Ranfurly	Colorado	One well
Redwater	Lower Cretaceous	
Rolling Hills	Colorado	One well
Suffield	Milk River	Small flow. Used locally
Tilley	Milk River	Local utility and farm use. Small flows
Valleyview	Lower Cretaceous	One well
Willingdon	Lower Cretaceous	

III THE PROBLEM OF DELIVERABILITY

In addition to the problem of the reserves of natural gas, there is the important and closely related problem of the deliverability of the gas. Reserves are only of value in proportion to the extent which they may economically be made available to the market AT THE TIME AND AT THE RATES REQUIRED BY THE MARKET. In Alberta, where the market requirement is comparatively low in the summer and extremely high in the winter, the situation is particularly difficult. In addition to the characteristics of the market itself there are many other factors involved in determining whether a gas reserve can economically be developed to meet the demands of a given market. Evidence brought out in the hearings by Messrs. C. R. Hetherington, A. D. Brokaw, J. O. Lewis, D. G. Hawthorn, R. E. Davis, J. E. Dodge and others indicates the following factors to be of particular significance:

1. The characteristics of the market itself and particularly the relationship between the average daily requirement and the peak day requirements—i.e. the load factor.
2. Possibilities of storage of gas produced in off-peak periods for peak period use.

In the case of gas not associated with or produced with oil:

3. The magnitude of the gas reserve, its pressure and its depth.
4. The thickness, porosity, permeability and other physical characteristics of the gas sand.
5. Conservation restrictions on individual well production rates.
6. The number of wells which can be drilled in a field within the limitations both of reasonable economics and of Conservation Board regulations on well spacing.
7. The nature of the gas produced and the need for and characteristics of a processing plant.
8. The capacity and economics of the field gathering system.
9. The capacity and the economics of the main transmission line(s) to the market.

In the case of gas produced with oil—in addition to the applicable factors listed above:

10. The rate of development of the oil field and the rate of production of oil.
11. The gas-oil ratio and the trend of this ratio.

In the case of gas associated as a gas cap with oil in the reservoir—in addition to the applicable factors listed above:

12. The need for deferment of deliberate production from the gas cap in the interests of optimum recovery of the oil.
13. The degree to which production from the gas cap is unavoidable with that of the oil.

The Characteristics of the Market

The characteristics of the market are of tremendous importance since they establish the deliverability requirements which must be met. The most useful single index for measuring the characteristics of a market is the load factor, ordinarily expressed as a percentage, and representing the ratio between the average daily and the peak day demand. In the Province of Alberta the load factor is especially low, being about 40% in the southern part of the Province served by the Canadian Western Natural Gas System and about 38% in the northern part of the Province served by Northwestern Utilities Limited. This low load factor results primarily from the extremes of weather encountered in Alberta. A contributing factor, however, is that a large proportion of the total market requirement is for gas required for domestic purposes—at present this use accounts for over one-third of the total. This part of the requirement, used largely for space heating, is most sensitive to "degree-day" or weather conditions. The industrial portion of the load is not so sensitive to weather extremities and contributes to higher load factors or more favourable market conditions. With the industrial growth of the Province the load factor will improve in proportion.

Storage Possibilities

The possibility of improvement in the effective characteristics of the market through the utilization of storage facilities, is one which has already served to alleviate the difficulty of the deliverability problem in the southern part of the Province. Reference is to the current use of the Bow Island field and the gas-cap portion of the Turner Valley field for storage of gas produced with the oil during the summer months from the Turner Valley field for use during the winter months to meet the high peak requirements.

Theoretically with adequate storage facilities the effect of the load factor of the market could be virtually eliminated so far as its impact on the actual fields supplying the gas is concerned. This ideal situation is rarely attainable.

Unfortunately, the Board received little evidence concerning the possibilities of developing further storage fields. In its opinion, however, the value of off-peak storage should not be lost sight of. The development of adequate storage fields is important not only in insuring future deliverability for the internal requirements of the Province but also for the supply of markets outside the Province.

The Magnitude of the Reserve, Pressure, Depth and Other Physical Factors

The magnitude of the reserve, its pressure and those other physical factors which determine the ability of individual gas wells to produce, are in part reflected by the results of production tests of the wells. Results of three kinds of such tests were produced in evidence at the hearings. The so-called "drill-stem tests", of which many were reported, are unfortunately not too revealing and give only a general idea of the physical ability of the well tested to produce gas for short periods and under virtually "wide open" conditions. "Production tests", also carried out under open flow conditions, are more reliable but less plentiful. Results of such tests indicate the ability of a well to produce for short periods at zero back pressure and at the prevailing reservoir pressure. The production characteristics of wells at lesser reservoir pressures, such as will exist after withdrawals, may be estimated with the aid of generalized knowledge but cannot, from such tests, be predicted with much certainty. The comprehensive "back pressure tests", available for only a relatively few wells, are more reliable and give far more information on the future production characteristics of the well, provided they are properly conducted. From the results of such back pressure tests, along with a reliable estimate of the gas reserve, it is possible (as brought out by Messrs. Hetherington, Dodge, Davis, Lewis and others) to make fairly reliable estimates of the present and future physical production characteristics of those wells WHICH HAVE BEEN TESTED IN FIELDS FOR WHICH THE RESERVES ARE REASONABLY WELL KNOWN. The extrapolation of such estimates to undrilled wells and to entire fields introduces an element of uncertainty which only time and further drilling and testing can remove.

While all applicants and many operating companies made available to the Board the results of those tests which had been conducted on wells and in fields of interest, the truth of the matter is that in many cases only drill-stem tests have been conducted and in some others the results of the production or back pressure tests were quantitatively uncertain. The comprehensive back pressure tests which have been conducted in both Pincher Creek and Jumping Pound are, unfortunately, none too conclusive because of the many special problems encountered. (New tests currently under way at both Pincher Creek and Jumping Pound will help to clarify the deliverability problem at these fields.) On the other hand, extremely good data were made available on certain of the older, well developed fields, especially Viking - Kinsella.

It should be pointed out that the lack of good production tests is in large part a result of the fact that when there is no market for the gas of a particular field there is little incentive for the operator to conduct extensive tests on his wells.

Conservation Restrictions on Production Rates

With respect to conservation restrictions on individual well production rates, the latest revisions of the Regulations under The Oil and Gas Resources Conservation Act, 1950, do not specify maximum permissible rates for wells producing gas. For many years a maximum rate for dry gas wells was set at 25% of the absolute open flow, equivalent to an allowable rate of 25% of the rate at which the well could physically produce at zero back pressure. Even before the question of gas export arose the Board was giving consideration to a revision of this historical and arbitrary 25% figure. At the time of the revision of the Regulations, however, the Board was not prepared to issue a substitute regulation regarding gas production rates but did not wish its hands tied to the 25% figure. For this reason the regulation was temporarily omitted with the knowledge that control could be exercised by Board order if required at any time.

While arbitrary, the 25% figure is still not too unreasonable and has for many years been employed in gas fields in the United States. As Dr. Brokaw pointed out in giving evidence on this subject, from the viewpoint of conservation, good operating practice and safety, the 25% open flow figure reflects a safety factor which increases throughout the life of the well. (It is generally conceded that reservoir damage may result if an excessive differential pressure is maintained at the sand face; also that the differen-

tial corresponding with flow at 25% of maximum is not excessive even for a new well. The adherence to the 25% formula means progressively smaller sand face differentials—or increase in the safety factor—as the well's potential decreases.) Dr. Brokaw made clear that he felt such an increase in safety factor to be unnecessary but that, unfortunately, he was unable to recommend an administrative practice which could properly correct the situation. None the less, the Board is of the opinion that some relaxation of the 25% open flow figure could and should be permitted in the declining years of a field.

Restrictions on Well Spacing

Restrictions on the number of wells which can be drilled within a given area are imposed both by regulatory practice and economics. The regulatory practice of the Conservation Board is generally to permit one gas well in each 640 acre tract, although this is varied to meet special conditions such as may exist at Jumping Pound and Pincher Creek. Regulatory restriction, however, is seldom the factor which in reality limits the number of wells which may be drilled in a field. Economics enters the problem during the earlier stages and the operator expects each new well to bring a return which will justify its costs. For example, while there are probably some 385 sites based upon 640-acre spacing in the Viking-Kinsella field, evidence of R. E. Davis is to the effect that only 150 to 175 wells could be drilled economically. Dr. Brokaw, on the other hand, indicated that some 300-370 wells could be drilled on the basis of a "utility rate of return".

The Nature of the Gas

The nature of the gas produced at the well can have a decided bearing upon the deliverability which may be developed. First, all gases which contain hydrogen sulphide and/or carbon dioxide must be processed for the removal of these components. This means that the economics of the processing plant must be considered along with the economics of drilling and producing wells. Such plants often can operate at 10% to 20% over design capacity but these figures cannot be greatly exceeded. Accordingly, the design plant capacity must be within 10% to 20% of the peak day deliverability of the field. Secondly, many gases, for example those which will be produced from the Jumping Pound and the Pincher Creek field, contain higher hydrocarbons (propane, butanes, pentanes, hexanes and heptanes and heavier) in amounts which must be removed and recovered, either to produce a marketable residue gas, or in the interests of conservation and optimum utilization, or both. In such cases, a more expensive processing plant is required and the economics and the producing programme are made even more rigid.

This is not to suggest that the capacity of a processing plant should without qualification determine the maximum rate at which gas may be delivered from a field. The situation is rather that the cost of drilling, the cost of the plant, the physical ability of wells to produce, conservation restrictions and the estimated recoverable reserve must all be considered together and the overall economics of the operation must be reasonable. Along this line of thought, considerable evidence was presented to the effect that where expensive plants and costly drilling are involved, operation of both wells and plant should be at or near full capacity at all times. Thus, it has been suggested that at Jumping Pound, and particularly at Pincher Creek, the ratio between the average daily and the peak day production, i.e. the producing load factor, should not be less than 70% to 80%.

The Capacity and Economics of Gathering Systems and Transmission Lines

It has been established that the capacity and the economics of the field gathering system are also important in determining the rate at which a gas may be made available to a market. A field gathering system must be designed in the light of the overall economics of the project. This ordinarily requires that the gathering system have a capacity greater than that required early in the life of a field when pressures are high, but perhaps less than that which could be employed later in the life of a field after pressures have declined. While extensions, looping of lines, and the use of booster compressors will permit an increase in the gathering capacity, the degree to which this may be done economically is limited.

A similar situation exists with respect to the capacity and the economics of the main transmission line(s).

Rate of Development and Production From Oil Fields

In the case of gas produced with oil, in addition to many of the factors discussed above, the rate of development of the oil field and the rate of production of oil are of obvious importance. A case in

point is that of the Leduc oil field, where current gas production is chiefly solution gas, the production of which is unavoidable with oil. In this particular case it is not too difficult to estimate the rate at which the oil field will approach complete development. The estimation of the oil production rate from the field, however, is extremely difficult since, within the limits of good conservation practice, it is dependent not only upon the total demand for oil produced in the Province but also upon the allocated share of that demand to the Leduc field.

The Gas - Oil Ratio and Its Trend

The gas-oil ratio and the trend of the ratio are also of great importance in the case of gas produced with oil. This ratio is known accurately at any one time but its future values can not be predicted with much certainty. The disparity in the evidence of Mr. Dixon and Mr. Pot relative to the Leduc D-3 pool is indicative of the difficulties involved in the forecasting of gas-oil ratios.

The Need for Deferment of Gas-Cap Gas

For cases such as the Leduc D-3 gas cap where gas is associated as a separate gas cap with oil in the reservoir, the need for deferment of deliberate gas-cap production is important in assessing the deliverability of such gas. The need for deferment of gas-cap production in the interests of optimum recovery of oil is a problem in petroleum reservoir engineering requiring the assessment of the probable efficacy of possible water drive, solution gas, and other oil discharging mechanisms. In most cases of gas-cap occurrences it is found desirable to defer any deliberate production of the gas cap in order to insure the existence throughout the life of the oil field of the necessary expulsive force to permit a proper recovery of the oil. This deferment may be for twenty, twenty-five or as much as thirty years, depending upon the rate at which the oil field itself is produced and on the physical characteristics of the reservoir.

Unavoidable Production of Gas-Cap Gas

The complete deferment of gas-cap production is not normally possible, however, and to some extent production of the gas cap is unavoidable with that of the oil. The degree to which gas-cap gas is produced with the oil depends upon the thickness of the oil-saturated sand, its physical characteristics, the rate at which oil is produced, the manner in which the well is completed, and many other intangibles. The fact of the matter is that regardless of the efforts taken to avoid gas-cap production, a certain and an increasing amount of such gas will be produced with the oil. Evidence of Messrs. Dixon, Pot, Lewis and Hawthorn is to this effect. The amount of such unavoidable gas-cap production is extremely difficult to estimate and, in fact, can only be guessed.

Summary

Recapitulating, the problem of deliverability is seen to be a very complex one involving as it does the load characteristics of the market, the possibility of off-peak storage, physical characteristics of the gas and/or oil sands, the nature of the gas, the capacity and economics of processing plants, gathering and transmission lines, conservation restrictions on production rates and well spacing, market and proration problems, and petroleum engineering problems related to the optimum recovery of oil.

For this reason deliverability projections are at best uncertain. They can be made and should be made but they must be considered in the light of the many factors involved and the reliability of the data on which they are based. Moreover, as pointed out by Messrs. Lewis and Hawthorn probably the most important single factor in the deliverability problem is the magnitude of the reserves themselves.

IV PRESENT AND FUTURE REQUIREMENTS OF THE PROVINCE

Present Requirements (Estimates for the year 1950)

Present annual consumption of natural gas, exclusive of field and field processing plant use and exclusive of propane and butane or "LPG," is:

	Domestic MMMcf.	Commercial MMMcf.	Industrial MMMcf.	Total MMMcf.
C. W. N. G. System	7.3	4.3	9.4	21.0
N.U.L. System	8.5	6.4	4.9	19.8
Other, including local systems (1)	3.0	1.9	2.1	7.0
Total	18.8	12.6	16.4	47.8

The peak day requirements and load factors for the Canadian Western Natural Gas Company and the Northwestern Utilities Limited Systems are:

	Peak Day MMcf.	Load Factor %
C.W.N.G.	145	39.5
N.U.L.	145	37.5

(1) Local systems serving the communities of Devon, Medicine Hat, Redcliffe, Athabasca, Bonnyville, Brooks, Lloydminster, Redwater, St. Paul, Suffield, Turner Valley, Vermilion, Wainwright. The total requirement of 7.0 MMMcf has been assumed to be made up of 2.1 MMMcf under industrial which is the requirements of the Medicine Hat and Redcliffe industries; the remainder has been split arbitrarily between domestic and commercial.

Present Fields Connected

To meet the present requirements of the two major distributing systems the following fields, with the indicated reserves of marketable gas and the indicated present developed deliverability, are connected to the respective systems:

	1950 Requirement MMMcf	1950 Peak Day MMcf.	Fields Attached	Estimated Marketable Reserves Jan. 1, 1951 MMMcf.	Present Developed Deliverability MMcf. per day
C.W.N.G. System					
	21.0	145	Turner Valley	300	95
			Bow Island (2)	15	50
			Foremost (3)	12	
			Jumping Pound (4)	540	33.5
			Total	867	178.5
N.U.L. System					
	19.8	145	Viking-Kinsella	582	182
			Leduc-Woodbend (5)	723	16
			Total	1305	198

(2) This field is used for storage of gas produced from Turner Valley during the summer months and is available only to meet winter peak day requirements.
(3) This field is used primarily to meet winter peak day requirements.
(4) This field was not attached during 1950 but will be available to meet 1951 requirements.
(5) This field was used to a limited extent during 1950 but will be in full use during 1951 and thereafter.

The industrial load for the Province may be divided approximately into three categories as follows:

	MMMcf.
Industrial General (6)	11.7
Industrial Raw Material (7)	1.7
Utility and general power generation	3.0
Total	16.4

(6) Including industrial direct fuel, industrial steam generation, industrial power generation.
(7) Including the direct use of lean natural gas as a chemical raw material. The figure is based upon 50% of the current total requirement of the CM. and S. Company, Alberta Nitrogen Plant.

Assuming the provincial population in 1950 at 887,000, the figures for the total requirements of the Province may be reduced to the following per capita basis:

Domestic Mcf per year	Commercial Mcf per year	Industrial Mcf per year	Total Mcf per year
21.2	14.2	18.5	53.9

The present developed deliverability at Viking-Kinsella is based upon the sixty-five wells which are actually connected to the gathering system, whereas some seventy-eight wells have been drilled and all of these could be made available to give an estimated deliverability of some 218 MMcf per day from Viking-Kinsella.

In the Canadian Western Natural Gas System the total developed deliverability during 1950 (before Jumping Pound was attached) was some 145 MMcf per day allowing no margin over the estimated peak day requirements of 145 MMcf.

No attempt has been made to set out in detail the annual and peak day requirements and the characteristics of the attached fields of the various local systems throughout the Province. It is believed that for the most part these systems will have to depend upon the deliverability of adjacent reserves at least until further gathering and transmission lines are constructed in the wake of further development.

Trends

The trend in the use of natural gas is and has been upward at a substantial rate. Evidence of this was submitted by Mr. F. A. Brownie on behalf of both the Canadian Western Natural Gas Company and Northwestern Utilities Limited. Mr. Brownie presented information showing the increasing use of gas for domestic, commercial and industrial purposes over the years 1930 to 1950. This information for the C.W.N.G. System, the N.U.L. System and the entire Province is presented graphically in Figures 2, 3, and 4. Referring to Figure 2, it will be noted over the past decade that there has been a very rapid increase in the total consumption of gas for the C.W.N.G. System. Over this period the growth has been from some 9 MMMcf per year to over 20 MMMcf, a gain of over 100% in ten years, or more than 8% per year. A substantial portion of this gain is attributable to the growth in the industrial requirement which increased from 2.3 MMMcf per year in 1940 to over 9 MMMcf in 1950, reflecting a growth of nearly 300% in ten years or nearly 15% per year.

Figure 3 which presents the data for the N.U.L. System reflects a similar growth in the northern part of the Province. The total requirement for gas in this area increased from slightly less than 4MMMcf per year in 1940 to nearly 20 MMMcf per year in 1950, a growth of 400% in ten years or about 17% per year. In this case, however, the proportion of the growth in each of the domestic, the commercial and the industrial categories is about equal as indicated by the fact that until the year 1950 these lines are nearly parallel to one another. The large growth in industrial requirement in 1950 is due to the attachment of the City of Edmonton power plant load.

Figure 4 indicates the trend in the requirements for the entire Province. It may be considered as an addition of Figure 2, Figure 3 and corresponding estimated information for the remainder of the Province. Referring to the total requirement it will be seen that this requirement has increased from some 15 MMMcf per year in 1940 to about 48 MMMcf per year in 1950 reflecting an overall increase in total provincial requirement of some 220% in ten years or over 12% per year. It is interesting to observe from Figure 4 that over the years the commercial requirement which started out much below the domestic requirement has gradually approached it.

The trends reflected by Figures 2, 3 and 4 include two effects, that of the increasing per capita requirement and that of the increasing population. In order that these effects may be separated to give a closer insight into the problem, population figures for the cities of Edmonton and Calgary and the Province as a whole are presented in Figure 5. For comparative purposes, population figures for Canada are also shown. Data have been obtained from the Canada Year Book 1950 and other reliable sources.

ANNUAL GAS CONSUMPTION MMMcf

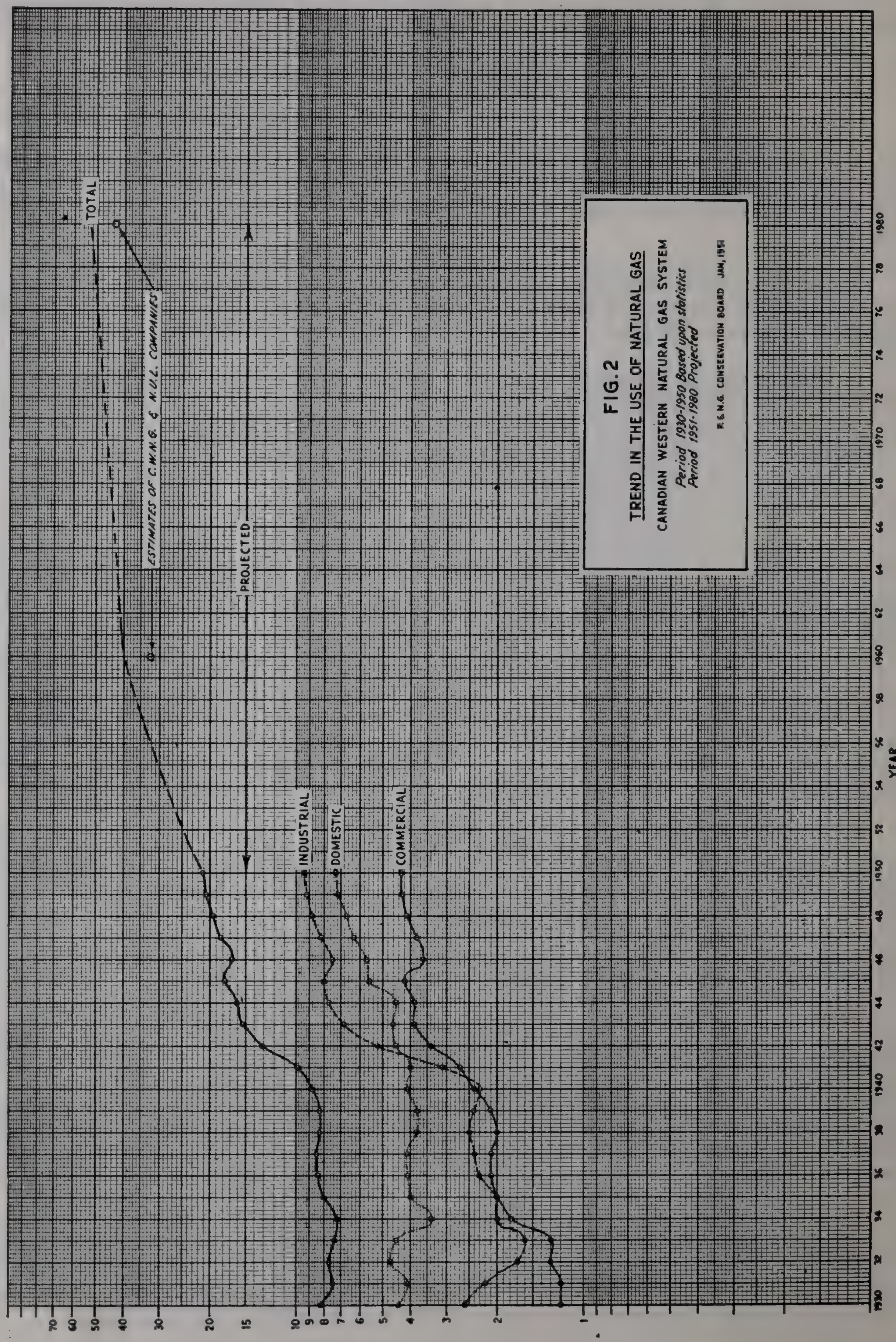


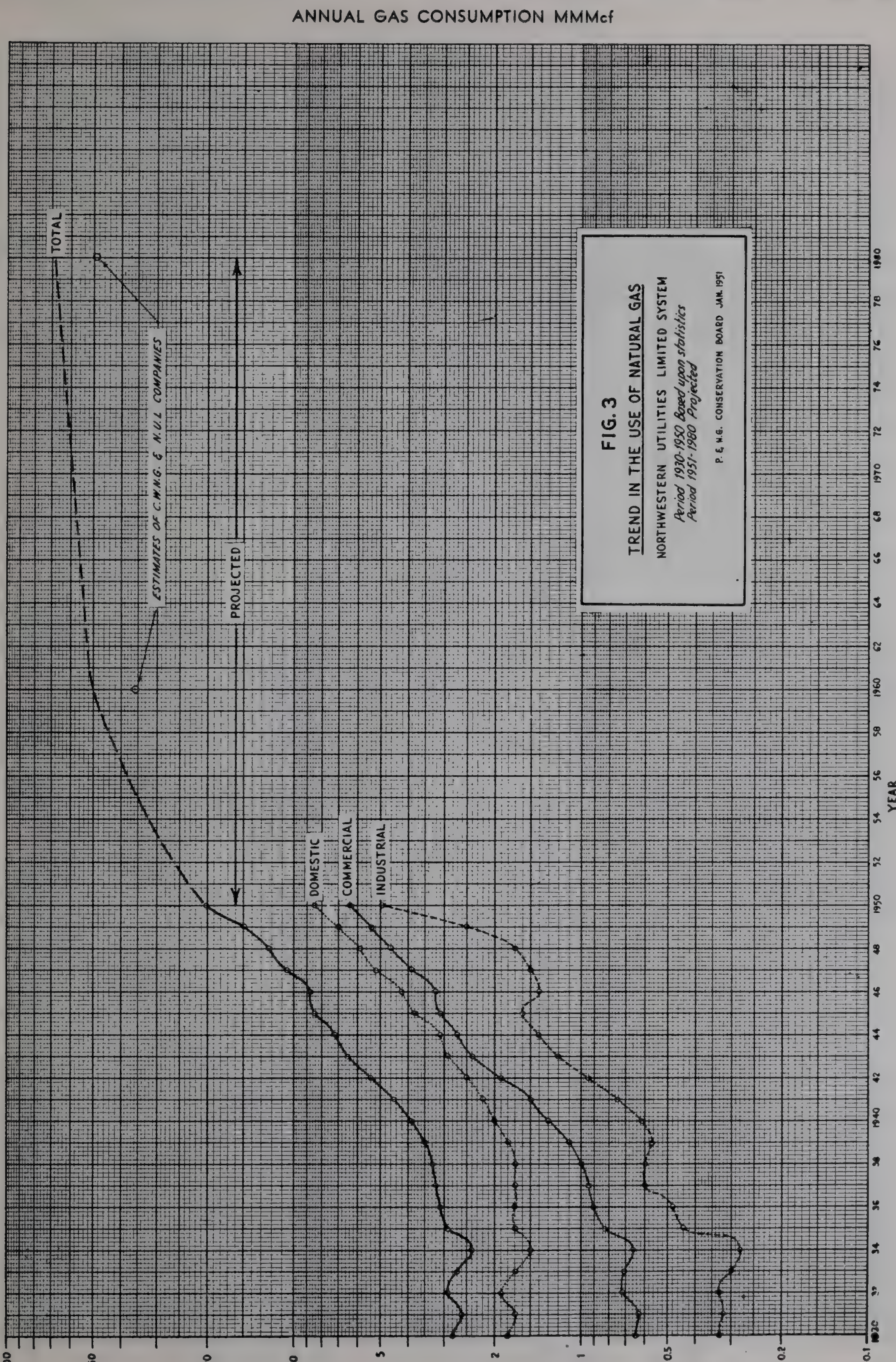
FIG. 2

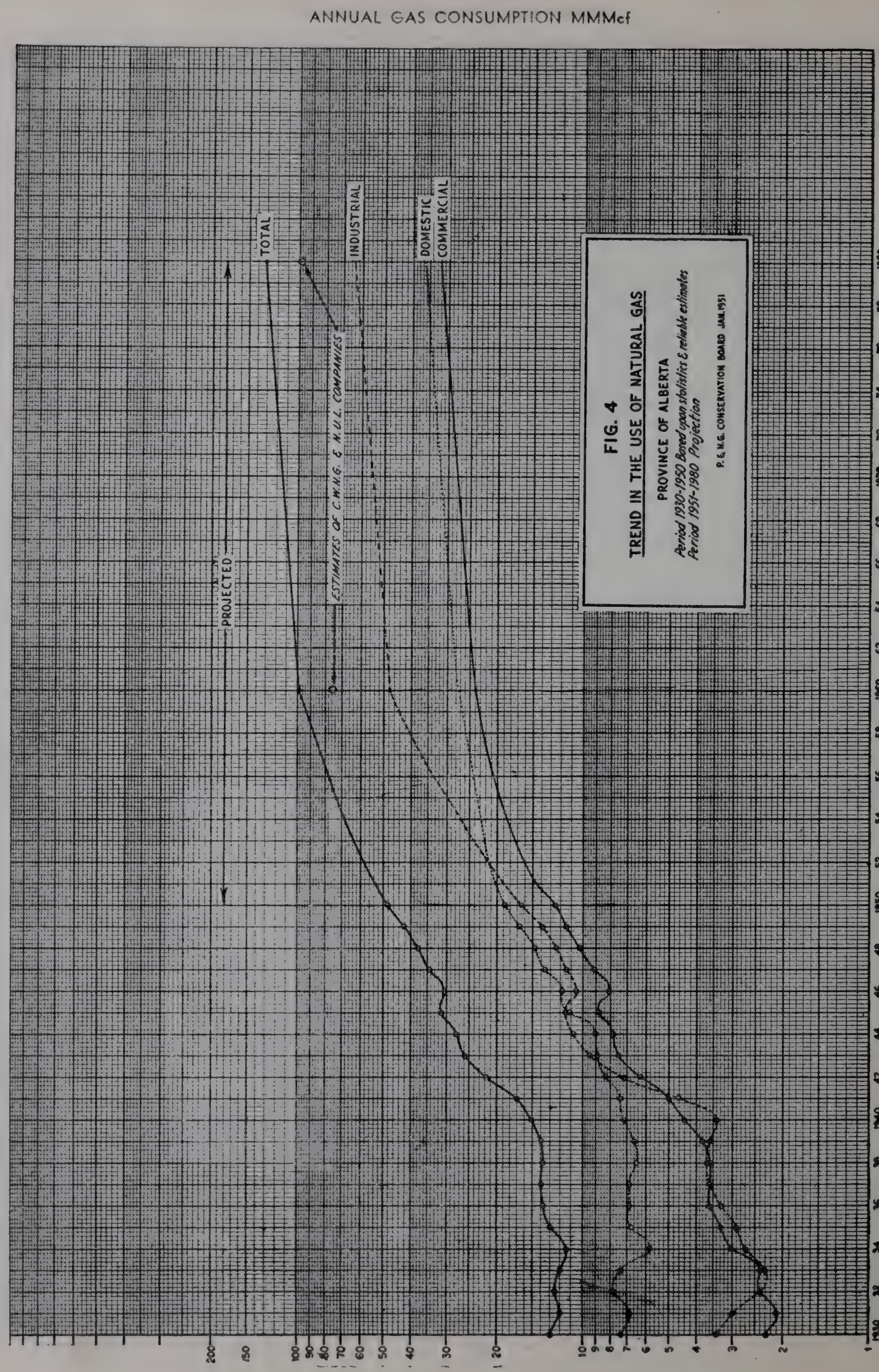
TREND IN THE USE OF NATURAL GAS

CANADIAN WESTERN NATURAL GAS SYSTEM

Period 1930-1950 Based upon statistics
Period 1951-1980 Projected

P. & N.G. CONSERVATION BOARD JAN., 1951


ANNUAL GAS CONSUMPTION MMMcf
TOTAL
ESTIMATES OF C.W.N.G. & N.U.L. COMPANIES
PROJECTED
DOMESTIC
COMMERCIAL
INDUSTRIAL
YEAR
FIG. 3
TREND IN THE USE OF NATURAL GAS
NORTHWESTERN UTILITIES LIMITED SYSTEM
Period 1930-1950 Based upon statistics
Period 1951-1980 Projected
P. & N.G. CONSERVATION BOARD JAN. 1951

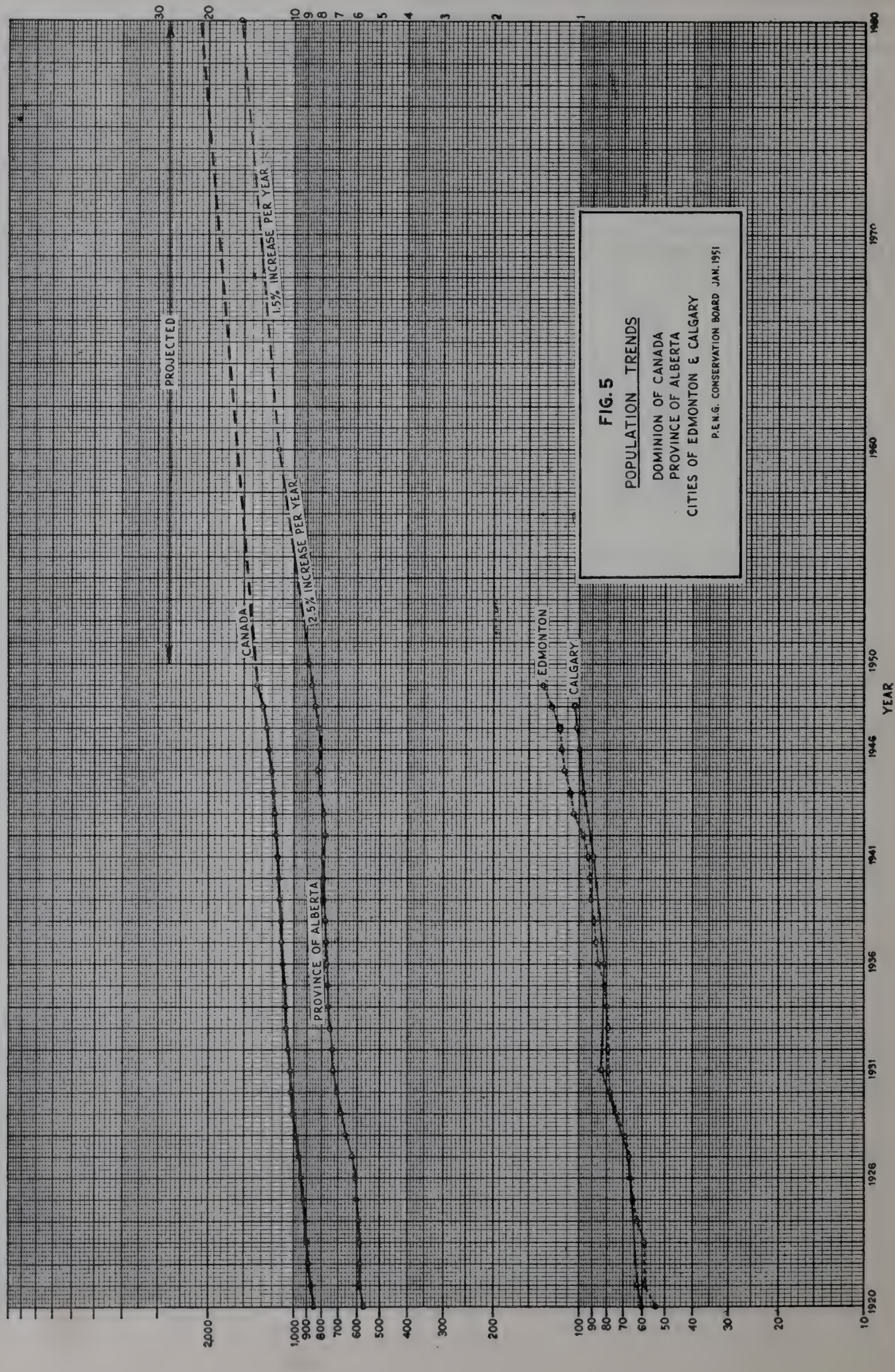

ANNUAL GAS CONSUMPTION MMMcf
TOTAL
INDUSTRIAL
DOMESTIC
COMMERCIAL
PROJECTED
ESTIMATES OF C.W.N.G. & N.U.L. COMPANIES
YEAR
FIG. 4
TREND IN THE USE OF NATURAL GAS
PROVINCE OF ALBERTA
Period 1930-1950 Based upon statistics & reliable estimates
Period 1951-1980 Projection
P. & N.G. CONSERVATION BOARD JAN. 1951

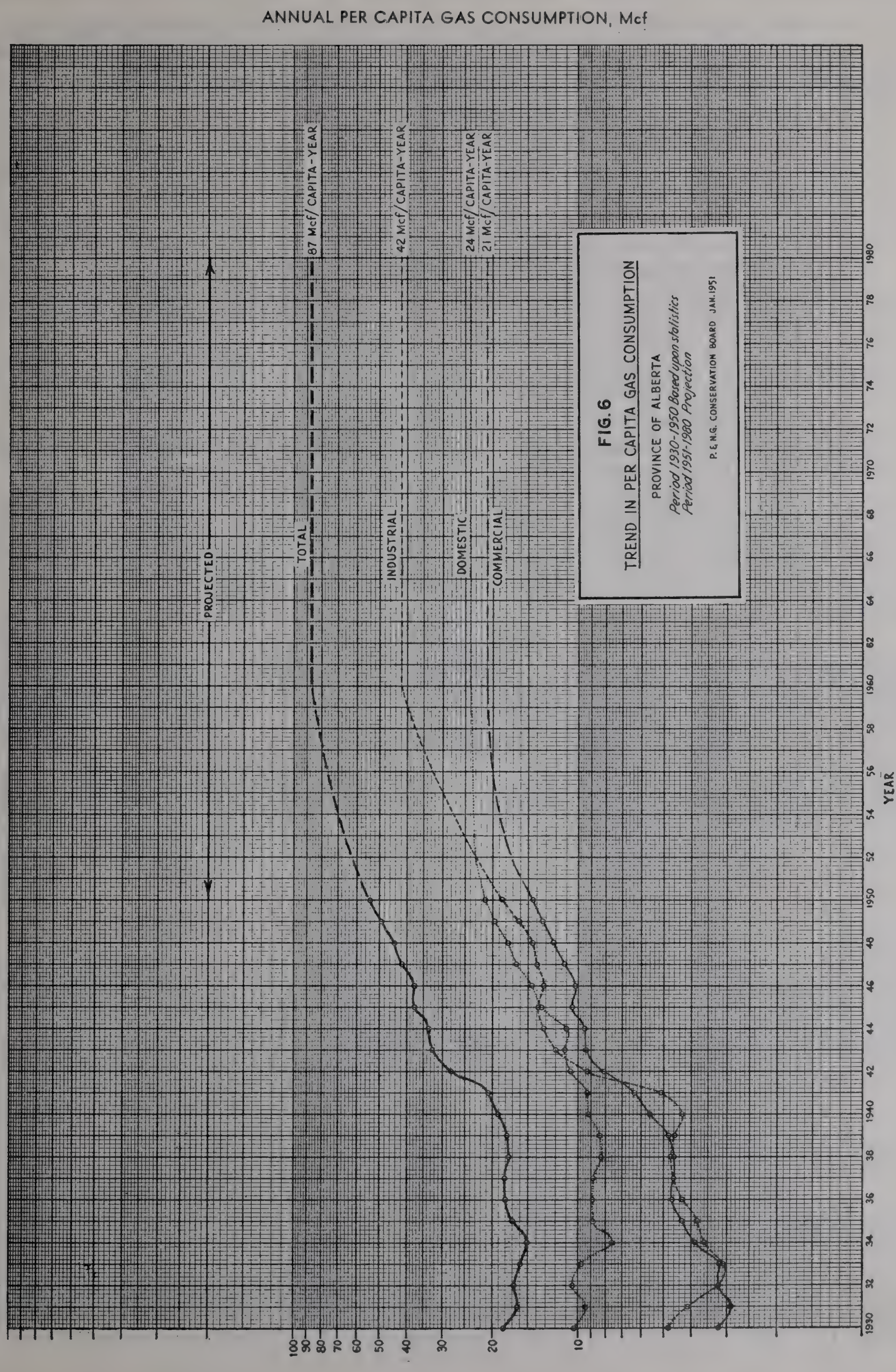
This figure reflects the fact that the growth of the Province of Alberta over the past thirty years has closely paralleled that of Canada as a whole and over the past twenty years the population of Alberta has been close to 7% of that of Canada. The average growth of the Province of Alberta over the past twenty years has been slightly over 1% per year. The cities of Edmonton and Calgary have been growing at slightly greater rates. This is a reflection of the general increase in urbanization in the Province and is measured by the fact that the ratio of the population of the two cities to that of the Province has been increasing over the years at a remarkably steady rate just over 1% per year.

Employing the population data of Figure 5, the provincial requirements shown on Figure 4 for the past 20 years may be reduced to a per capita basis and are so illustrated in Figure 6. Referring to this figure, it may be seen that whereas the total per capita requirement during the early thirties was between 15 and 20 Mcf per year, it has now grown to over 50 Mcf per year representing an increase greater than 150 per cent over the past ten years. This is a notable per capita growth. The same situation is reflected by the per capita figures for the individual categories of domestic, commercial and industrial use.

POPULATIONS OF EDMONTON, CALGARY AND ALBERTA IN THOUSANDS

Population of Canada in Millions




ANNUAL PER CAPITA GAS CONSUMPTION, Mcf
PROJECTED
TOTAL
87 Mcf/CAPITA-YEAR
INDUSTRIAL
42 Mcf/CAPITA-YEAR
DOMESTIC
24 Mcf/CAPITA-YEAR
COMMERCIAL
21 Mcf/CAPITA-YEAR
YEAR
FIG. 6
TREND IN PER CAPITA GAS CONSUMPTION
PROVINCE OF ALBERTA
Period 1930-1950 Based upon statistics
Period 1951-1980 Projection
P. & N.G. CONSERVATION BOARD JAN. 1951

While statistics such as those presented in the foregoing are invaluable in the establishment of trends, judgment and knowledge of changing conditions, techniques and technology are also most important in the present problem. Factors which must be considered in applying judgment to the trends include:

1. The trend towards urbanization of population.
2. The increasing physical standard of living in both urban and rural areas.
3. The outstanding and recent development in technology bringing to, or within reach of the Province,—
   (a) the petrochemical industry,
   (b) agricultural products processing industries,
   (c) synthetic rubber and its need for carbon black,
   (d) high efficiency reciprocating gas engines and their possibilities in power generation and industry,
   (e) the gas turbine and its possibilities for power generation.
4. The accelerating industrialization of the Province resulting from such developments as listed in (3) above and stimulated by the growth of the oil and gas industries.
5. The possibilities of industrial development of atomic energy.
6. The possibilities of developments resulting in the more efficient utilization of coal—of which Alberta has tremendous resources.
7. The possible saturation in the type of industrial development which might be attracted by Alberta natural gas—i.e. a given sized reserve with corresponding quantities of gas and petrochemical raw materials can attract and support only a certain amount of industry based upon it—further industrial growth being contingent upon further discoveries.

Future Requirements

Evidence on the probable future requirements of the Province for natural gas was presented by the Westcoast Transmission Company; by the Northwest Natural Gas Company; by Mr. Brownie on behalf of the Canadian Western and Northwestern Utilities Companies; by The Research Council of Alberta and by Mr. J. R. Donald with respect to industrial requirements; and by The Alberta Power Commission with respect to the requirements of gas for power generation.

The final estimates of Westcoast Transmission Company, Northwest Natural Gas Company and the two Utility Companies for the two major distribution systems of the Province are:

	Requirements for 30 years MMMcf.	Requirements for 50 years MMMcf.
Westcoast	2093	3211
Northwest	1962	——
Utility Companies	2208	——

All three groups seemed in substantial agreement concerning the requirements of the remainder of the Province. The Utility Companies estimate of 210 MMMcf for thirty years, or 350 MMMcf for fifty years was adopted by Westcoast Transmission Company while Northwest Natural Gas used a figure of 180 MMMcf for thirty years. Accordingly the figures for the Province as a whole are:

	Requirements for 30 years MMMcf.	Requirements for 50 years MMMcf.
Westcoast	2303	3561
Northwest	2142	——
Utility Companies	2418	——

Other applicants did not prepare independent estimates but indicated their agreement with the figures advanced by Mr. Brownie for the Utility Companies. Mr. J. R. Donald suggested that the total demand for gas would probably double every ten years.

So far as the Board was able to determine, the estimates of the applicants and the Utility Companies were based upon increases in demand more or less proportionate to contemplated population increases with modest provision for additional industrialization of the Province. The evidence of The Re-

search Council of Alberta, The Alberta Power Commission and Mr. J. R. Donald suggest a much greater industrial requirement than reflected by the evidence of others.

For the Power Commission, Mr. Russell stated that "the gas required by 1960 for the generation of electric power could be estimated at 20 billion cubic feet." This compares with Mr. Brownie's estimate of 7.8 billion cubic feet for the same year and with a Research Council suggestion that growth of gas consumption to 9 billion cubic feet per year for power consumption should be provided for.

The Research Council and Mr. Donald both spoke of the tremendous industrial possibilities of the Province and emphasized potential petrochemical developments. As brought out in the evidence, industrial use of natural gas and related compounds divides itself into:

(1) Use of dry or lean natural gas as a fuel for industrial processes, steam generation, etc.
(2) Use of dry or lean natural gas, primarily for its methane content, for the manufacture of carbon black, ammonia and a relatively few other products which may be produced economically using methane as a raw material.
(3) Use of ethane recovered from dry or wet natural gas for conversion to ethylene and then to other products.
(4) Use of LPG (propane and/or butanes) for conversion by partial oxidation or other processes to a wide range of chemicals; use of butane for conversion to butadiene; use of isobutane for the manufacture of alkylate—important constituent of aviation gasoline.

Categories 1 and 2 above require ordinary or pipe line natural gas—in category 2 the gas is required both for industrial fuel and as a raw material. In the third category only the ethane content of the gas would be required as a raw material, but pipe line natural gas would normally be required as a fuel. In the fourth grouping, only propane and/or butane would be used as raw materials but, again, pipe line natural gas would normally be required as a fuel. It is understood that fuel requirements can be quite high in this latter grouping.

By-product gases from refinery cracking operations contain methane, ethane, ethylene, propane, propylene and higher hydrocarbons. Many of these are equally suitable—in some cases more suitable—for supplying categories 3 and 4. Such material must therefore be considered, along with ethane, propane and butane from natural gas, when considering the availability of suitable petrochemical raw materials.

It would appear therefore that, if the future requirements of Alberta's industries and potential industries are to be protected, reasonable allowance should be made for natural gas for fuel purposes for all the above categories. Moreover natural gas for raw material purposes should be provided for category 2 and consideration should be given to the availability of propane, butane and related compounds—both from wet natural gas and from refinery gases—from the viewpoint of the raw material requirements of categories 3 and 4.

In this connection it should be noted that propane and butane can be made available economically from wet natural gas only if there is a market for the residue or pipe line gas. This market could be either an internal or an export market but a high load factor is greatly to be desired.

The Research Council has made an estimate of the probable industrial requirement for natural gas and states, "It is anticipated that the amount of natural gas used in this Province in the next fifty years will be considerably more than two- or three-fold, possibly three to four times that used today." Mr. Donald considered this to be "much too conservative." Companies applying for export permits believed the viewpoint to be too optimistic.

Recognizing the difficulties in estimating the industrial requirements, and concerned over the disparity in the views expressed, the Board has analyzed trends in Texas and Oklahoma and made a reanalysis of the Alberta problem from a different viewpoint.

An analysis of the trends in Texas and Oklahoma when conducted on a per capita basis indicates the existence in these areas of the same type of per capita growth which has been observed in the past decade in the Province. Because of differences in the degree-day requirements, extent of urbanization, and facilities for transportation of the products of industry, the per capita figures from Texas and Oklahoma are not directly applicable to the Alberta problem. It is believed, however, that the growth trends which

may be observed in these areas reflect the fact that the growth which has been experienced in Alberta is not a "freak" thing unlikely to continue.

The Board therefore feels justified in extending the per capita figures for domestic, commercial and industrial consumption in the Province to the year 1960 on the basis of a continuing but gradually diminishing growth. In the case of both domestic and commercial requirements, it was considered that the present per capita figures of approximately 21 and 14 would increase slowly to 24 and 21 by the year 1960. This is believed to be conservative since it reflects a per capita growth rate much less than has actually been experienced over the decade 1940 to 1950. In the case of the industrial requirement, after giving consideration to the evidence of The Research Council of Alberta, The Alberta Power Commission, Mr. J. R. Donald, and to the contrary views, and in view of the many modifying factors mentioned earlier, the per capita figures were assumed to increase at a rate of about one-half of that which has been experienced over the past ten years. The assumed per capita growth for these three categories of use and for the total requirement is reflected by the dotted lines of Figure 5.

The Board is reluctant to extrapolate these per capita trends beyond the year 1960 and for this reason assumes the 1960 per capita figures to be applicable over the period 1960 to 1980. Further justification for this procedure, is that unlimited growth will not take place unless further natural resources in the way of oil, gas and other are developed. For this reason the per capita growth beyond, say, 1960 might be assumed partly contingent upon the discovery and development of further raw materials (including oil and gas) which could then support the further growth.

In order to convert the per capita figures to total provincial figures, it was necessary to estimate the population growth for the Province over the period 1950 to 1980. Careful consideration was given to the views of The Research Council of Alberta, and of Mr. Menzies, City Commissioner of Edmonton, to the trends reflected in Figure 6 and to the various factors which might operate to alter these trends. It was decided that the most realistic approach would be to assume a population growth for the Province equal to 2½% per year for the period 1950 to 1960 and 1½% per year thereafter. This estimate is reflected by the dotted line of Figure 5.

Combining the per capita estimates shown in Figure 6 with the population estimate of Figure 5 a final estimate of provincial requirements under the three categories, domestic, commercial and industrial, was obtained. These requirements were then assigned to the C.W.N.G. System, to the N.U.L. System and to the local systems approximately in accordance with the present relationship between the requirements of these systems but reflecting the greater growth anticipated by Mr. Brownie and others in the Northwestern Utilities Limited System. The final figures for the Province as a whole and for the two major systems are shown as the dotted lines on Figure 4 and Figures 2 and 3.

With reference to Figure 4 it will be seen that the extensions of the trends established over the past twenty years do not seem in the least unreasonable. They reflect not only an anticipated population growth but also, during 1950-1960, a per capita growth. This is what actually happened in Alberta during the past twenty years and is what has happened in Texas and Oklahoma.

These figures, particularly in the case of the industrial category, were scrutinized and compared with those advanced by various witnesses. It is the Board's opinion that they reflect reasonable provision for power, petrochemical and other industrial development of an order which may be expected from known resources.

For comparative purposes points indicating the 1960 and 1980 requirements as estimated by Mr. Brownie are shown on Figures 2, 3 and 4. The level of industrial development predicted by Figure 4 is of the same order as that suggested by The Research Council of Alberta—probably less than what Mr. Donald had in mind when he referred to the conservative nature of the Research Council figures.

The Board fully recognizes the difficulties and pitfalls of forecasting requirements and appreciates the need for a realistic outlook. It is, however, the considered opinion of the Board that even Mr. Brownie's estimates, higher than those of either the Westcoast Transmission Company or the Northwest Natural Gas Company, are too low and that a more realistic estimate of the future requirements is reflected by the projections of Figures 2, 3 and 4. For convenience, the estimates indicated by these projections are presented in tabular form in Tables 3 and 4 immediately following this section.

Table 3 presents the year by year estimates for the Province as a whole with subdivision, as in Figure 4, into the domestic, commercial and industrial categories. The totals for the thirty year period 1951-1980 inclusive are:

Domestic	873.7 MMMcf
Commercial	751.7
Industrial	1,434.5
	3,059.9 MMMcf

Table 4 presents the year by year allocation to the C.W.N.G. System, the N.U.L. System and the remainder of the Province. As mentioned earlier this allocation is to some extent arbitrary but is believed to reflect realism with respect to the relative growth of the two systems. Estimated load factors and peak day requirements are also tabulated for the two systems. These figures were arrived at after consideration of the contemplated increase in industrial load and the beneficial effect of such loads on the load factor. No allowance was made for any increase in interruptible load which might further improve the peak day situation. The distribution of the provincial total for the thirty year period, and the maximum peak day requirements are:

	Annual MMMcf.	Maximum Peak Day (1980) MMcf.
C.W.N.G. System	1239.6	318
N.U.L. System	1553.6	388
Remainder of Province	266.7	
Total	3059.9 MMMcf	*706 MMcf

* Exclusive of remainder of Province for which the peak day requirements were not estimated.

TABLE 3

ESTIMATE OF NATURAL GAS REQUIREMENTS

Province of Alberta, Jan. 1, 1951-Dec. 31, 1980

(Based Upon the Projections of Figure 4)

Year	Domestic MMMcf	Commercial MMMcf	Industrial MMMcf	Total MMMcf
1951	20.1	14.5	19.0	53.6
1952	21.4	16.1	21.1	58.6
1953	22.2	17.2	24.0	63.4
1954	22.9	18.6	26.8	68.3
1955	23.6	19.6	30.3	73.5
1956	24.1	20.4	33.2	77.7
1957	24.9	21.2	36.9	83.0
1958	25.7	22.2	40.5	88.4
1959	26.5	22.9	44.2	93.6
1960	27.3	23.8	47.7	98.8
1961-62	27.6	24.1	48.3	100.0
1963-64	28.6	25.0	49.9	103.5
1965-66	29.4	25.7	51.4	106.5
1967-68	30.2	26.4	52.9	109.5
1969-70	31.2	27.3	54.5	113.0
1971-72	32.0	28.0	56.0	116.0
1973-74	33.1	29.0	57.9	120.0
1975-76	34.2	29.9	59.9	124.0
1977-78	35.0	30.6	61.4	127.0
1979-80	36.2	31.6	63.2	131.0
Totals	873.7	751.7	1434.5	3059.9

TABLE 4

ESTIMATE OF NATURAL GAS REQUIREMENTS

Province of Alberta, Jan. 1, 1951-Dec. 31, 1980
Allocation Between Distributing Systems

Year	C.W.N.G. System Annual MMMcf	C.W.N.G. System Load Factor	C.W.N.G. System Peak Day MMcf	N.U.L. System Annual MMMcf	N.U.L. System Load Factor	N.U.L. System Peak Day MMcf	Remainder of Province Annual MMMcf	Total Annual MMMcf
1951	23.2	40	159	23.3	38	168	7.1	53.6
1952	24.9	40	171	26.5	41	177	7.2	58.6
1953	26.8	41	180	29.3	41	196	7.3	63.4
1954	28.6	41	191	32.3	42	211	7.4	68.3
1955	30.6	41	205	35.4	43	226	7.5	73.5
1956	32.2	42	211	37.9	43	242	7.6	77.7
1957	34.1	42	222	41.1	45	250	7.8	83.0
1958	36.1	42	235	44.4	46	265	7.9	88.4
1959	38.0	43	242	47.6	46	284	8.0	93.6
1960	39.9	43	254	50.8	47	296	8.1	98.8
1961-62	40.4	43	258	51.3	47	298	8.3	100.0
1963-64	41.7	44	260	53.1	48	303	8.7	103.5
1965-66	42.9	44	268	54.8	48	314	8.8	106.5
1967-68	44.1	44	275	56.3	48	322	9.1	109.5
1969-70	45.5	44	283	58.2	48	333	9.3	113.0
1971-72	46.9	45	285	59.4	48	339	9.7	116.0
1973-74	48.5	45	295	61.6	48	351	9.9	120.0
1975-76	49.6	45	303	64.2	48	367	10.2	124.0
1977-78	50.8	45	310	65.7	48	376	10.5	127.0
1979-80	52.2	45	318	67.9	48	388	10.9	131.0
Total	1239.6			1553.6			266.7	3059.9

V THE PROBLEM OF MEETING THE REQUIREMENTS OF THE PROVINCE

At the specific request of the Board the applicants have each shown how in their opinion and based upon their estimates of the reserves, market requirements, and deliverability characteristics, the future requirements of the Province may be met. This was illustrated by year to year calculations showing how, in the opinion of the applicants, both the annual and the peak day requirements could be met from the reserves remaining at the end of each year and the prevailing deliverability of the various fields.

As indicated in an earlier Section, the Board has arrived at an estimate of Established Reserves of the Province below that advocated by any of the applicants. Moreover the Board's estimate of market requirements, discussed in Section IV, is greater than suggested by the applicants or by the two utility companies. The Board's findings with respect to the Established Reserves of the fields which now provide gas for two chief utility systems and of fields which might be expected to augment these supplies are, however, in fair agreement with individual estimates submitted by the applicants. The Board's estimates of the maximum deliverability which can be developed in the various fields, while not greatly different than that suggested by the applicants and others, vary from these to some extent. This variation is due in part to different interpretations put upon some of the tests and to differences in the estimated gas in place and discount figures employed.

For these reasons—i.e. differences in reserve, requirement and deliverability estimates — the Board has had to make a re-analysis of the problem of meeting Alberta's requirements. This analysis, detailed year by year for the cases of the two major distribution systems in the Province, is presented in Tables 5 and 6. In the case of the remainder of the Province and the local systems a detailed analysis was not made because none of the applicants proposed the removal of gas from areas adjacent to local systems and since it has been assumed that these systems would have to be dependent upon adjacent reserves.

Evidence of several witnesses indicated that year by year "deliverability schedules" could be considered as indicative of the manner in which requirements might be met but should not be interpreted too literally in view of the many contingencies involved. In particular such schedules are apt to be deviated from in the light of changing economics, the acquiring of storage facilities, the establishment of further reserves and changes in the market requirements. The Board concurs in these views and realizes that deliverability schedules must be considered in the light of many uncertainties. It is the Board's opinion, however, that adequate protection can only be ensured for the Province if it is possible through "illustrative schedules" to indicate a way in which the requirements can be met with the established reserves. Tables 5 and 6 are presented from this viewpoint—i.e. as illustrative deliverability schedules to show how the requirements might be met or what deficiencies might exist based upon best present knowledge.

The Canadian Western Natural Gas System

Table 5 presents such an illustrative deliverability schedule for the Canadian Western Natural Gas distribution system. The tabulation is based upon the estimated annual and peak day requirements of this system as presented in Section IV. Details of the requirements are set out in columns 2, 3, 4 and 5 for the period 1951 through 1980.

For the purpose of showing the situation as it would be without the addition of further major reserves the tabulation assumes that only Turner Valley, Jumping Pound, Foremost, Bow Island and the California Standard Area of the Foremost field are available to the utility. These fields with the exception of the California Standard Area, are now attached to the system. It is the Board's opinion that the California Standard Area of the Foremost field would be a most logical addition.

The estimated future producing characteristics of the Turner Valley field are indicated in columns 6, 7 and 8. The gas from the Turner Valley field, a large portion of which is solution gas produced unavoidably with oil, must be absorbed by the market, repressured or stored, in the interests of conservation. The Board has assumed that the entire production of marketable gas from Turner Valley would continue to be made available to the system with storage in the Turner Valley gas cap and Bow Island during off-peak periods for use to meet peaks. On the basis of an established reserve of 300 MMMcf, the Board

believes that Turner Valley will be able to supply annual amounts ranging from over 18 MMMcf in 1951 and 1952 down to about 9 MMMcf in the middle 1970's. The corresponding peak day potentials of Turner Valley are estimated as ranging from 86 MMcf in 1951 to just over 50 MMcf in 1973 or 1974. The availability of gas from Turner Valley after this time is questionable.

Columns 9, 10, 11 and 12 indicate the manner and the degree in which Jumping Pound might supply the system. A development of the field from five wells in 1951 to a maximum of 13 wells in 1956 has been assumed as best meeting the requirements. It will be noted that annual withdrawals starting at about 5 MMMcf in 1951, increasing to some 19 MMMcf in the late 1950's and decreasing to about 6 MMMcf in 1980 are contemplated. The corresponding peak day production increases from 28 MMcf in 1951 to nearly 70 MMcf in the late 1950's and decreases thereafter to about 20 MMcf in 1980. These figures reflect a load factor for the Jumping Pound Field increasing from 48% in 1951 to 80% in the late 1950's and remaining constant thereafter. It should be emphasized at this point that this represents only one way in which the Jumping Pound field might be operated. The low load factor in the first 6 to 8 years is undesirable from the viewpoint of the economics of operating the field and its necessary processing plant. On the other hand without the introduction of another reserve before this time this load factor is about what will be required to meet the needs of the system.

The situation as projected for the Foremost field is shown by columns 13, 14, 15 and 16. It is assumed that this dry gas field will continue to be used, as now, primarily to meet peaks. With five wells in the field the ability to meet peaks, along with small annual withdrawals, is estimated to range from nearly 16 MMcf per day in 1951 down to about 6 MMcf per day in 1980. This reflects a very low load factor, as indicated by column 16, but from the point of view of meeting the needs of the C. W. N. G. System this seems logical.

Column 17 indicates the estimated ability of the Bow Island field to meet peak day requirements assuming no net withdrawals during the thirty-year period.

With these four fields it is estimated that both the annual and the peak day requirements of the C.W.N.G. System may be met until the middle 1950's. At about this time, even assuming the complete development of Jumping Pound, it appears necessary to assume the addition of the Foremost California Standard Area. The ability of this area to supply the system, assuming five wells drilled, is reflected in Columns 18, 19, 20 and 21. With the small reserve of this area and taking into consideration the fact it is a dry gas field, it seems most logical that this area also be employed primarily to meet peak day requirements. Accordingly, with small annual withdrawals, the peak day capacity of the area is estimated as declining from 16 MMcf at the start to some 7 or 8 MMcf by 1980.

The California Standard Area of the Foremost field, however, has neither the reserve nor the deliverability characteristics to save the system from requiring the attachment of further reserves before 1960.

Columns 22, 23, 24 and 25 indicate the deficiencies estimated for the system from the late 1950's through to 1980. These figures represent the characteristics required of additional reserves needed to protect the C.W.N.G. distribution system for the remainder of the thirty-year period. It will be observed that the total deficiency is estimated at over 600 MMMcf and the peak day deficiencies increase from 22 MMcf per day in the late 1950's to over 230 MMcf per day by 1980. The Board is of the opinion that an Established Reserve of marketable gas of the order of 1100-1300 MMMcf is required to meet these annual and peak day deficiencies shown for the C.W.N.G. system in Table 5.

The illustrative deliverability schedule of Table 5 should not be interpreted too literally. It does, however, serve to indicate that the estimated future requirements of the C.W.N.G. system, with Turner Valley, Jumping Pound, Foremost, Bow Island and the Foremost California Standard Area all assumed connected and developed to their indicated maximum, can only be met until the late 1950's and that at or about this time further substantial reserves with the ability to meet increasing volume and peak requirements will have to be added to the system. The peak day problem could be alleviated by the utilization of further storage fields. While the Board believes that such storage projects should be undertaken, little evidence on this matter was received and no account has been taken of it in Table 5.

The problem of how best to supply the indicated deficiencies of the C.W.N.G. system is complex and difficult to answer at this time. There is of course the possibility that both Jumping Pound and

Turner Valley may deliver more gas than estimated. As indicated previously the Board is hopeful that further development may increase the established reserve at Jumping Pound by 100 to 150 MMMcf or so. Possibly further development will indicate higher individual well deliverabilities than have been estimated.

Looking to other areas of Established Reserves in the southern part of the Province, the following suggest themselves:

Field	Established Reserves MMMcf
*Black Butte	32
*Manyberries	58
Princess-Patricia	101
*Pendant d'Oreille	213
Pincher Creek	1170
*Smith Coulee	15
Total	1589
*Pakowki Lake Fields	318

From the viewpoint of simple arithmetic this would seem to indicate a surplus of some 300 MMMcf since only 1100 to 1300 MMMcf are estimated as necessary to protect the C.W.N.G. system. A number of economic factors obviate this conclusion, however.

The Pincher Creek field is the only single field which has a reserve close to that required to meet the estimated deficiencies. A deliverability analysis of this field indicates that with graduated development from 3 wells in 1958 or so, to 21 wells in the mid 1970's, the bulk of the deficiency could be met. Actually the analysis showed a remaining deficit of about 60 MMMcf with peak day deficiencies in the last 6 or so years reaching some 140 MMcf in 1980. Even if it were assumed that this reflected adequate protection, the economics of the operation are questionable. As Mr. Davis pointed out, Pincher Creek is not particularly suited to the needs of the C.W.N.G. system for two reasons:

1. The field is a long way from both the consuming center and the existing lines.
2. Condensate fields with their high well and plant investment require a large volume and a high load factor market to be able to deliver gas and liquid products at reasonable prices.

The volume of gas required by the C.W.N.G. system in the late 1950's would average only 10-20 MMcf daily, and this would increase to about 50 MMcf daily in 1964, about 70 MMcf daily in 1970 and finally to about 100 MMcf daily in the late 1970's. Such a slowly developing load does not lead to the most effective development of the field and its auxiliary plant equipment. The load factor which could be offered to Pincher Creek by the C.W.N.G. system on this scheme is estimated to range from below 50% in the late 1950's to just over 60% in the early 1970's, and finally reaching a desirable 80% in the mid 1970's. Such a load factor could only reflect an inefficient operation and expensive gas. These facts, when considered with the transmission distance to the C.W.N.G. system, do seem to indicate the need for a better solution to the problem.

The load factor situation might be corrected in either of two ways:

1. By the development of a storage field, capable of high deliverability to meet winter peaks.
2. By the use, along with Pincher Creek, of a dry gas field capable of good deliverability and economically capable of operating at very low load factor. Such a field might be used with Pincher Creek much as Foremost is presently employed with the other fields in the C.W.N.G. system.

While the Board believes that much might be accomplished through the development of a storage scheme it has no evidence to confirm the existence of physically and economically suitable storage reservoirs.

The dry gas fields of Princess-Patricia, and those in the Pakowki Lake area which might be considered as peak load producers are, unfortunately, also quite distant from the C.W.N.G. system, introducing a further long distance transmission problem and its costs.

From the purely physical viewpoint the Pendant d'Oreille field could be operated, with small annual withdrawal, to meet the worst of the C.W.N.G. system peaks, permitting Pincher Creek a desirable load factor. Solving the Pincher Creek load factor problem, however, introduces a problem in the economics

of operating the dry field on a peak only basis. Moreover it still does not provide a desirable high volume withdrawal from Pincher Creek.

As the Board sees the problem of meeting the C.W.N.G. system deficiencies, none of the possible solutions discussed above are desirable ones.

From the point of view of the C.W.N.G. system the acquisition of the Pincher Creek field to meet its deficiencies does not appear attractive unless it is the only solution of the problem. Operating costs including depreciation would mean expensive gas which no doubt would be discouraging to future industrial development.

Similarily from the point of view of the operators of the Pincher Creek field, meeting the deficiencies of the Canadian Western System is not an attractive proposition owing to:

(a) the long delay before being able to produce the field;

(b) the comparatively low annual withdrawal when production does commence;

(c) the low load factor.

Counsel for the City of Calgary in his brief to the Board suggested that if export were not permitted the problem of providing markets for those who have in good faith spent substantial amounts in developing gas for which there is at present no market might be met by provision for sharing the market. If this were done in the case of the C.W.N.G. system and the market were shared between Turner Valley, Jumping Pound, Pincher Creek, Princess-Patricia, and the Pakowki Lake fields it could only mean very expensive gas when the capital outlays and the operating costs involved are taken into consideration.

What seems to be needed is the development of some further dry gas reserves, the planning of a future peak sharing storage project, and the integration of the dry gas reserves, the storage scheme and Pincher Creek to meet jointly the requirements of the C.W.N.G. system and some export market proportionate to the increase in reserves.

Meanwhile, however, in the lack of any scheme which seems reasonable from the viewpoint of the owners of the reserves and the C.W.N.G. system, the Board cannot declare any gas from the following fields to be surplus to the requirements of the Province.

Black Butte
Manyberries
Princess-Patricia
Pendant d'Oreille
Pincher Creek
Smith Coulee

NORTHWESTERN UTILITIES SYSTEM

An illustrative deliverability schedule for the Northwestern system was prepared in the same manner as that previously described for the Canadian Western. Table 6 shows the projected requirements of the system through the years 1951 to 1980 in columns 2, 3, 4 and 5 under the heading "Total Requirements." The schedule is drawn to illustrate the annual and peak day quantities which can be expected from the two fields now connected to the system, assuming that no further reserves will be added during the period 1951-1980.

The estimated daily and annual withdrawals of gas from Leduc-Woodbend are based on the forecast presented by Imperial Oil Limited at the Joint Hearing for average daily gross gas expected to be produced with oil during the period 1950-1970, and has been discounted for field loss, plant shrinkage, and converted to a B.T.U. basis equivalent to Viking-Kinsella gas. The present capacity of the field processing plant has not been considered in this schedule.

Assuming that Leduc-Woodbend field reaches a peak annual production of about 19 MMMcf in the late 1950's and then production rates remain constant to 1980, the Viking-Kinsella field will be required to supply the balance of the requirements of the system and to take care of the peak day load. The tabulation indicates that the reserves and deliverability of Viking-Kinsella are adequate to supply the peak day

requirements up to the early 1960's, when an anticipated maximum of 175 wells would be required. At about that time deficiencies will occur and will steadily increase to over 48 MMMcf in the year 1980, at which time a deliverability of about 335 MMcf per day will be needed to meet the peak day requirements. The total indicated deficiency is 475 MMMcf.

As in the case of Table 5, this deliverability schedule should be considered as indicative of the situation but is not intended for literal interpretation. The indications are, however, that the 30 year requirements of the N.U.L. system cannot be met from Leduc-Woodbend and Viking-Kinsella, and that by the early 1960's new and substantial reserves capable of meeting increasing average and peak day loads will be required.

It is the opinion of the Board that further Established Reserves of the order of 1100 to 1300 MMMcf (depending upon their deliverability characteristics) must be made available to the system to meet this situation.

An examination of the Established Reserves listed in Table I indicates that the following might be considered physically available:

Field	Established Reserves MMMcf
Bon Accord	7
Excelsior	15*
Golden Spike	24*
Joseph Lake	15*
Legal	4
Morinville	68
Picardville	9
Provost	78
Redwater	50**
Total	270
Total, excluding Excelsior, Golden Spike, Joseph Lake and Redwater	166

*Gas Production may be deferred. See Table I.
**Economics of gathering is uncertain. See Table I.

Excluding reserves which may be deferred too long to meet the early deficits of the system, and excluding Redwater for which the economics are particularly questionable, an Established Reserve of only 166 MMMcf is available. This reserve, even if it could all be gathered and supplied economically to the system, could only serve in token capacity so far as is now known.

It, therefore, appears to the Board that further development, quite possibly in the Morinville-Picardville area, or other areas within economic reach, is required to establish the sufficient reserves to meet the system deficits contemplated as occurring in the early 1960's. Until such further reserves are established to meet these deficiencies the Board cannot declare any gas from the following fields to be surplus to the requirements of the Province:

Bon Accord
Excelsior
Golden Spike
Joseph Lake
Legal
Morinville
Picardville
Provost
Redwater

Remainder of the Province

As mentioned previously, the type of detailed analysis conducted for the two major distribution systems is not, in the Board's opinion, practical for the remainder of the Province. It appears to the Board that gas can be supplied to local consuming centres only if:

(1) An adequate reserve of gas is established in the immediate vicinity of the area thus permitting the necessary low transmission costs required for small volumes.

or (2) A distributing or gathering line of a utility system passes or can be brought within economic reach of the area.

or (3) A main transmission line for possible export should pass or could be brought within economic reach of the area.

So far as the first possibility is concerned about all the Board is able to do at this time is to consider as reserved from general use those fields now supplying local systems or considered as logical sources of supply of such systems. This reservation is indicated by Column 14 of Table I, which shows a total Established Reserve of some 380 MMMcf for "Local Use". While this total figure compares favourably with the total estimated requirements for the remainder of the Province, i.e. 267 MMMcf, it should be pointed out that a large block of these reserves, 320 MMMcf, lie in the Medicine Hat field.

The possibilities suggested by (2) are included in the provisions for the two major systems since the projections have been based upon past growth which includes system expansion to new centres.

The possibilities suggested by (3) occur only if an exportable surplus is developed elsewhere. These possibilities, therefore, must be considered at the time of and along with further consideration of the export of surplus gas.

Table 5

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE CANADIAN WESTERN NATURAL GAS COMPANY DISTRIBUTION SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
	Estimated Requirements				Turner Valley			Jumping Pound				Foremost				Bow Island	Foremost — Cal. Stand. Area				Deficiencies			
Year	Annual MMMcf	Peak Day MMcf	Load Factor %	Daily Average MMcf	Annual MMMcf	Peak Day MMcf	Load Factor %	No. Wells	Annual MMMcf	Peak Day MMcf	Load Factor %	No. Wells	Annual MMMcf	Peak Day MMcf	Load Factor %	Peak Day MMcf	No. Wells	Annual MMMcf	Peak Day MMcf	Load Factor %	Annual MMMcf	Peak Day MMcf	Load Factor %	Daily Average MMcf
1951	23.2	159	40	63.5	18.1	86.0	57.7	5	4.9	28.0	48	5	0.2	15.8	3.5	29.2								
1952	24.9	171	40	68.2	18.7	87.0	58.9	6	6.0	34.0	49	5	0.2	15.6	3.6	34.4								
1953	26.8	180	41	73.5	16.3	85.0	52.5	7	10.2	40.0	70	5	0.3	15.2	5.4	39.8								
1954	28.6	191	41	78.3	15.1	83.0	49.8	10	13.5	53.0	69	5	0.2	15.0	3.7	40.0								
1955	30.6	205	41	83.8	15.4	81.0	52.1	12	14.9	65.0	63	5	0.3	14.6	5.6	44.4								
1956	32.2	211	42	88.1	15.0	79.0	52.0	13	16.8	66.3	69	5	0.3	14.3	5.7	45.7	5	0.1	5.7	5.3				
1957	34.1	222	42	93.3	14.4	77.3	50.9	13	19.1	68.7	78	5	0.3	13.9	5.9	46.1	5	0.3	16.0	5.1				
1958	36.1	235	42	98.8	13.6	75.0	49.7	13	18.3	62.5	80	5	0.3	13.5	6.1	46.5	5	0.3	15.6	5.2	3.6	21.9	46.0	10.0
1959	38.0	242	43	104.0	13.0	73.0	48.8	13	16.9	57.8	80	5	0.3	13.0	6.3	47.0	5	0.3	15.1	5.4	7.5	36.1	57.0	20.6
1960	39.9	254	43	109.3	12.2	71.0	47.1	13	15.8	54.0	80	5	0.3	12.6	6.5	47.4	5	0.3	14.7	5.6	11.3	54.3	57.0	31.1
1961-62	40.4	258	43	111.0	11.8	68.7	47.1	13	15.1	51.8	80	5	0.3	12.0	6.8	48.0	5	0.3	14.0	5.9	12.9	63.5	56.0	35.7
1963-64	41.7	260	44	114.3	11.1	64.6	47.1	13	12.3	42.2	80	5	0.3	11.4	7.2	48.6	5	0.3	13.3	6.2	17.7	79.9	61.0	48.5
1965-66	42.9	268	44	117.8	10.6	61.6	47.1	13	10.8	37.0	80	5	0.3	10.6	7.7	49.4	5	0.3	12.4	6.6	20.9	97.0	59.5	57.6
1967-68	44.1	275	44	121.0	10.2	59.3	47.1	13	9.8	33.8	80	5	0.3	9.9	8.3	50.1	5	0.3	11.7	7.0	23.5	110.2	58.5	64.5
1969-70	45.5	283	44	124.7	9.8	57.0	47.1	13	8.9	30.4	80	5	0.3	9.1	9.0	50.9	5	0.3	11.0	7.4	26.2	135.6	53.0	72.0
1971-72	46.9	285	45	128.5	9.5	55.2	47.1	13	8.0	27.3	80	5	0.3	8.5	9.6	51.5	5	0.3	10.2	8.0	28.8	142.5	55.0	78.9
1973-74	48.5	295	45	133.0	9.2	53.5	47.1	13	7.3	25.0	80	5	0.3	7.8	10.5	52.2	5	0.3	9.5	8.6	31.3	156.5	55.0	85.7
1975-76	49.6	303	45	136.0	1.3	7.6	47.1	13	6.8	23.4	80	5	0.3	7.1	11.5	52.9	5	0.3	8.8	9.3	40.9	212.0	53.0	112.0
1977-78	50.8	310	45	139.3				13	6.4	21.8	80	5	0.3	6.5	12.6	53.5	5	0.3	8.2	10.0	43.8	228.2	52.5	120.2
1979-80	52.2	318	45	143.0				13	6.0	20.5	80	5	0.3	6.0	13.7	54.0	5	0.3	7.5	10.9	45.6	237.5	52.5	125.0
TOTAL	1239.6				300.0				319.2				8.7					7.3			605.6			
Established Reserve					300.0				540.0				17.0					14.0						
Percent Withdrawn					100%				59%				52%					52%						

Table 6

The Petroleum and Natural Gas Conservation Board

ILLUSTRATIVE DELIVERABILITY SCHEDULE FOR THE NORTHWESTERN UTILITY COMPANY DISTRIBUTION SYSTEM

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	Total Requirements				Leduc-Woodbend		Viking-Kinsella				Deficiencies			
Year	Annual MMMcf	Peak Day MMcf	Load Factor %	Daily Average MMcf	Annual MMMcf	Peak Day MMcf	No. Wells	Annual MMMcf	Peak Day MMcf	Load Factor %	Annual MMMcf	Peak Day MMcf	Load Factor %	Daily Average MMcf
1950														
1951	23.3	168	38	63.8	6.9	18.8	56	16.4	149.2	30				
1952	26.5	177	41	72.5	7.1	19.4	61	19.4	157.6	34				
1953	29.3	196	41	80.2	8.3	22.6	71	21.0	173.4	33				
1954	32.3	211	42	88.5	9.5	26.0	79	22.8	185.0	34				
1955	35.4	226	43	97.0	11.2	30.6	88	24.2	195.4	34				
1956	37.9	242	43	104.0	14.0	38.3	97	23.9	203.7	32				
1957	41.1	250	45	112.5	15.5	42.3	105	25.6	207.7	34				
1958	44.4	265	46	121.8	16.6	45.4	119	27.8	219.6	35				
1959	47.6	284	46	130.3	19.4	53.1	138	28.2	230.9	34				
1960	50.8	296	47	139.0	19.4	53.1	158	31.4	242.9	35				
1961-62	51.3	298	47	140.3	19.4	53.1	175	29.6	232.0	35	2.3	12.9	46.5	6.0
1963-64	53.1	303	48	145.5	19.4	53.1	175	24.5	197.0	35	9.2	52.9	47.5	25.2
1965-66	54.8	314	48	150.5	19.4	53.1	175	22.9	179.0	35	12.5	81.9	42.5	34.7
1967-68	56.3	322	48	154.3	19.4	53.1	175	20.2	158.0	35	16.7	110.9	41.5	45.9
1969-70	58.2	333	48	159.5	19.4	53.1	175	17.9	140.0	35	20.9	139.9	41.0	57.4
1971-72	59.4	339	48	163.0	19.4	53.1	175	16.6	130.0	35	23.4	155.9	41.0	64.0
1973-74	61.6	351	48	168.5	19.4	53.1	175	15.1	118.0	35	27.1	179.9	41.5	74.5
1975-76	64.2	367	48	176.0	19.4	53.1	175	14.0	109.0	35	30.8	204.9	41.0	84.3
1977-78	65.7	376	48	180.0	19.4	53.1	175	9.0	70.0	35	46.3	322.9	39.5	126.9
1979-80	67.9	388	48	186.0	19.4	53.1	175	7.8	61.2	35	48.5	334.9	39.5	132.9
TOTAL	1553.6				515.9			563.3			475.4			
Established Reserve					723.0			582.0						
Percentage Withdrawn					71%			97%						

VI GAS SURPLUS TO THE REQUIREMENTS OF THE PROVINCE

In the opinion of the Board none of the major reserves or any part of them could be allocated to a market outside of the Province.

There are scattered reserves in the northwestern, eastern and southeastern parts of the Province which could be classified as not within economic reach of the two major utility systems and, therefore, could be considered available to supply markets outside the Province. The Pakowki Lake fields might, in the opinion of some, be placed in this category but as stated previously the Board does not at the present time recommend that they be allocated for export.

In no areas other than in those tributary to the two major systems could an Established Reserve or a group of Established Reserves be considered, in the opinion of the Board, sufficiently large in the light of present information to justify the building of a pipe line as proposed by any of the applicants. The Board recognizes that further development could rapidly change this situation.

VII GENERAL COMMENTS

Future Possibilities — Marketing Problems

As mentioned earlier, geologists are unanimous in their opinion that the vast sedimentary deposits underlying the major portion of the Province offer great possibilities for the development of oil and gas reserves. The Board concurs in this view. Further reserves of gas will undoubtedly be found not only in the way of dry gas fields but also as gas associated with oil and condensate discoveries. Certain factors affecting the marketing of gas associated with oil and condensate have already influenced and will continue to influence the way such reserves can be developed.

Solution gas from oil-gas fields is produced unavoidably with oil. While the Board will tolerate a reasonable waste of solution gas, particularly in the early life of a field, when production reaches the point where the gathering of gas is economical, it requires that the economically recoverable liquid hydrocarbons be removed and that effective use be made of the residue gas. This means either that a steady market must be found for the residue gas (unless it is required for repressuring), or that an uneconomical repressuring scheme must be undertaken.

In the case of condensate fields, while recycling of the produced gas is sometimes economically desirable in the interests of recovery of liquid hydrocarbons, production allowables are usually set on a gas basis, and effective utilization of the gas is required.

In addition to treatment for the recovery of liquid hydrocarbons, the residue gas may also have to be treated to remove hydrogen sulphide, carbon dioxide and other impurities before it can be put into the pipe line. If the gas has a high hydrogen sulphide content it may be profitable to produce commercial sulphur, which is in short supply at the present time. Such recovery would aid in defraying the treating costs.

Pincher Creek is a good example of the condensate type of field. This field in addition to being able to supply large quantities of deliverable gas can also provide for every 100 million feet of residue gas some 3,500 barrels of natural gasoline, 700 barrels of butane, and 550 barrels of propane, the last two of which could serve as raw materials in petrochemical industries. In addition, some 430 tons of sulphur could be produced with every 100 million feet of marketable gas.

The high capital expenditure involved in drilling wells in this type of field and in building the necessary processing plants requires a relatively high daily throughput of gas with a load factor of 70% to 80% if the resultant products, including gas, are to be produced at a price which will be attractive to prospective customers. Thus, such fields are not basically suited to the supply of peak load requirements of utility systems.

With the exception of the Viking-Kinsella field the main sources of supply for the Northwestern and Canadian Western Systems are oil fields and a condensate field, viz., Jumping Pound. This

poses a problem of deliverability. The Northwestern System can depend at the present time on the Viking-Kinsella field for its peak demands but will not be able to do so within the next seven or eight years. A similar situation faces the Canadian Western System. Peak demands at the present time are provided from the Turner Valley gas cap and the Bow Island fields, but within the next seven or eight years they will also be faced with the problem of obtaining additional gas reserves to meet normal and peak demands.

The ideal way to supply provincial requirements, envisioning further discoveries of oil and condensate fields, would be to supply peak demands from economically available dry gas fields and to meet the base load with gas from oil or condensate fields. Alternatively, if adequate storage reservoirs were available, a high steady load could be taken from oil and/or condensate fields with summer storage utilized to meet winter peaks.

The Pakowki Lake dry gas fields in the southern part of the Province are owned and operated by McColl-Frontenac Oil and Union Oil Companies, who have applied to the Board for permission to export this gas to the State of Montana. The Established Reserves are comparatively small in the four fields involved (Black Butte, Pendant d'Oreille, Manyberries and Smith Coulee), amounting to 318 billion cubic feet. If permission were granted to export gas from these fields to the United States a valuable source of obtaining peak load gas would be lost to southern Alberta as well as possible storage reservoirs which the Board feels must be provided in order to cope with the low load factor maintaining in the Province. In addition, loss of these reserves to the United States' market would be contrary to the Government's enunciated policy of giving preference to Canadian consumers, particularly if it should be decided to utilize the Pincher Creek field to provide the base load for provincial or other Canadian requirements or both with the need for dry gas fields to meet peak demands.

Lack of Incentive

Lack of incentive caused by lack of markets has prevented many promising gas strikes from being developed. For over twenty years the Provincial Government has employed restrictive measures to prevent the export of gas with a view to protecting the interests of the people of the Province. These measures enabled the Government to prevent export unless with its permission. Not until The Gas Resources Preservation Act was passed, however, was an attempt made to state clearly and on what basis the Government would permit export. As a consequence, nobody would take the risk involved to develop gas fields except to supply the limited local markets. Even since the passing of The Gas Resources Preservation Act in July, 1949, very little has been done to follow up gas strikes with further development drilling, the reason given being that the operators do not think the risk worth while unless there is an assured market such as export would provide. As a result, comparatively little follow-up drilling has been done to evaluate gas strikes, and this has made it difficult for the Board and the applicants to prepare reserve estimates.

The present system of disposing of Crown lands with the proviso for the establishment of Crown reserves has been based primarily on oil development and not gas development. This also poses a problem. Gas unlike oil cannot be marketed by truck or rail transportation but only by pipe line. The size and length of pipe line which may be constructed for the economic marketing of gas depends upon the amount of reserve established.

Many of the recent and undeveloped gas strikes have been in thin sands, particularly the Lower Cretaceous and Viking.

In order to prove up a reserve of pipe line gas a comparatively large area must be explored and an opportunity given to lease large tracts out of it.

The present policy of the Board permits the spacing of one well to each 640 acres. This is generally considered a satisfactory spacing for economic development but may be varied to meet local conditions. This policy, coupled with diversification of ownership through establishment of Crown reserves on a checker-board system, makes it somewhat difficult for a company considering development of gas to acquire sufficient acreage at a reasonable cost to make the project worth while.

This was brought out in evidence before the Board with the suggestion that in both reservation and lease phase, Crown acreage might be disposed of on a "gas only" basis.

It was admitted that separation of "gas only" rights and oil and gas rights would be a difficult task, but nevertheless the fact remains that today Crown reserves add a serious complexity to the problem an operator faces in the development and delineation of dry gas reservoirs.

The Board concurs in the views expressed and recommends that some scheme be worked out whereby "gas only" rights may be obtained to gas producing zones on relatively large blocks of acreage.

Canadian Preference

The letter dated September 23rd, 1950, from the Honourable N. E. Tanner to the Board stated that it would as a matter of Government policy be a condition of any export permit that Canadian requirements must be given first priority. All the applicants before the Board at present, with the exception of McColl-Frontenac Oil Company Limited and Union Oil Company of California, propose supplying at least some Canadian requirements outside of Alberta.

Three of the applicants, namely, Northwest Natural Gas Company, Prairie Pipe Lines Limited, and Westcoast Transmission Company Limited, intend supplying the British Columbia market. The other, Western Pipe Lines, proposes supplying the Saskatchewan and Manitoba market.

In order to supply either the British Columbia or the Saskatchewan - Manitoba market, according to evidence presented to the Board, it is necessary at the present time to supply additional markets in the United States to make the pipeline project economically feasible. Northwest Natural Gas Company and the Westcoast Transmission Company each are applying for about 79 billion feet a year (fifth year requirements), of which 12.6 billion feet are for British Columbia requirements and the balance is to supply the Pacific Northwestern United States.

Prairie Pipe Lines Limited are applying for 100 million feet a day or 36.5 billion feet a year to supply the British Columbia market. The company admits that this is a great deal more than the British Columbia market can absorb initially but claims that its demand may eventually build up to this figure. The company further states it will take any gas over and above the 100 million feet a day to augment its supply for its proposed line in Texas to serve the Pacific Northwest United States and in the event that Alberta should be able to supply an additional 250 million feet a day, it would pipe gas from the United States to Eastern Canada on an exchange basis.

Northwest Natural Gas Company filed plans of several pipe line routes but considered its route "B" to be the best pipe line route from an engineering standpoint from Alberta to the Pacific Coast. Route "B" starts at Pincher Station and runs westerly to the Crowsnest Pass to Kingsgate, British Columbia. From Kingsgate the pipe line travels to Sand Point and Spokane and westerly to a point near Monroe, Washington. Here it splits into two sections, one going north to the British Columbia market and the other south to the Seattle-Portland area. In addition there are various laterals to supply specific marketing areas. The company intends to draw its supply of gas from the Pincher Creek and other Alberta fields through a proposed grid system.

Prairie Pipe Lines proposes to build its line from the Pincher Creek field through the Crowsnest Pass to connect up with its United States line at the Idaho-British Columbia border. The 100,000,000 cubic feet of natural gas per day that it would pipe from Alberta would be dedicated to the potential requirements of the market areas to be served in British Columbia, which include New Westminster, Vancouver, Victoria and Trail. The company intends to obtain its supply of gas from Pincher Creek.

Westcoast Transmission has amended its application to provide for transporting gas from the vicinity of the Pouce Coupe field in the Peace River area through the Pine Pass, thence to Prince George, thence to a point near Vancouver, where the line would be split, one branch going to Vancouver and the other south to the International Boundary and on to Washington and Oregon, with various laterals to supply specific marketing areas. It also proposes to construct, as and when required, a branch line from the vicinity of Prince George, B.C., through the Yellowhead Pass to a point in the vicinity of Edmonton for the purpose of connecting up with gas reserves in the vicinity of Edmonton. The company intends to obtain its supply of gas principally from the Whitelaw field and other fields in the Peace River area which it hopes to develop, augmented by supplies from fields north and west of Edmonton.

Western Pipe Lines proposes to draw its supply of gas from the Pincher Creek and other southern fields and transport it in a line to be constructed starting at or near Pincher Creek, following a

route through Swift Current, Brandon, Winnipeg, to the International Boundary, and thence to Duluth and Superior in Minnesota, with various laterals to supply other marketing areas. It is estimated this line will require 58.4 billion feet (fifth year requirements) per year, of which 19.5 billion feet would be for Canadian requirements. According to present consumption estimates this line would supply more Canadian requirements than any of the companies proposing to supply the British Columbia market.

The Major Utility Systems

The two major utility companies stated through their counsel that no gas should be exported from the Province until their requirements have been looked after for a period of fifty years. The question of what method should be employed to provide this protection and what policy should be followed by these systems in acquiring gas reserves to protect their consumers is a complex one.

Mr. R. E. Davis, an expert called by the two companies, testified before the Board that both the Canadian Western and the Northwestern Utilities systems would require to obtain additional reserves in amounts of approximately 750 billion and 500 billion cubic feet respectively within the next ten years, to ensure adequate reserves and deliverability for a period of thirty years. The Board concurs with Mr. Davis that additional reserves will have to be provided, but is of the opinion that larger reserves will be required and that they probably should be acquired earlier.

In reply to a question as to where the additional 500 billion for the Northwestern Utilities system might be acquired, Mr. Davis stated that there was a real possibility of more Devonian oil fields being found and that "even another Leduc" with a good gas cap might be found within 50 or 75 miles of Edmonton. In view of the present exploration programme and the prospects of success he did not consider it necessary for the utility "to go rushing into a deal in 1950". Mr. Davis' answer was premised on the assumption that all Leduc gas would be made available to the Northwestern Utilities System.

Dealing with the same subject, the counsel for the Northwestern Utilities Limited system stated in his brief to the Board:

"The natural source from which the Edmonton system might be expected to draw is the area north of the city close to its pipe lines and the proper conclusion probably is that a great deal more work ought to be done in that area immediately accessible to the Northwestern system for the purpose of ascertaining whether in those fields the additional gas required by the Northwestern system can be economically obtained."

No mention was made, however, as to whether the Utilities Company itself was prepared to carry out the work that ought to be done.

It is noteworthy also that the counsel for the Northwestern Utilities, (in cross-examination of W. D. C. MacKenzie, Assistant Manager of Imperial Oil Limited, in regard to the difference in price being paid by the Devon and Leduc Utility systems as compared to the price paid by the Northwestern Utilities for a supply of residue gas from the Leduc absorption plant) inferred that the Leduc gas was distress gas which had to find a market and that his company was able to obtain it at low cost in order to avoid the expense of re-pressuring the gas. This, despite the evidence of their own witness, Mr. R. E. Davis, that even with the supply of gas from Leduc, additional reserves of 500 billion cubic feet to supply peak demands would be required within ten years to ensure supply and deliverability for the next thirty years. If the Northwestern system had not been able to obtain a supply of gas from Leduc they would have had to find other reserves within a comparatively short time to protect their own consumers.

Mr. Davis, in discussing where the additional 750 billion cubic feet of reserves he considered necessary for the Canadian Western system might be acquired, had this to say:

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"Regarded as a potential source of gas for the Canadian Western system, the Pincher Creek field, despite its undoubtedly large reserve, is not as attractive as could be desired, first on account of its distance from the main market, the City of Calgary, and second because of the high capital and operating costs involved in producing the gas.

"Assuming that the transmission pressures now carried in the 16" line are close to a safe limit, an additional line from the field to Calgary would be necessitated if Pincher Creek were required to supply a large proportion of the Calgary demand.

"The two factors which appear to rule out the possibility of cheap gas from Pincher Creek are the drilling depths—over 12,000 feet—and the high hydrogen sulphide content of the gas—of the order of 9% with 7% carbon dioxide. Offsetting these factors would be the distillate recovered. The feasibility of commercial recovery of sulphur from this gas can depend upon a number of factors, including the size of the operation. Unless sulphur can be produced commercially, the cost of removing and disposing of the sulphur would be considerable.

"I regard the Pincher Creek field as having a very large reserve, probably exceeding one trillion cubic feet. This gas may be regarded as potentially available, in part at least, to Canadian Western, should it be required. Other potential sources, such as Jumping Pound or the Pakowki Lake area, may be more feasible sources to Canadian Western."

Counsel for Canadian Western Utilities, dealing with reserves in his brief to the Board, stated:

"This additional gas cannot be obtained from any presently connected source of supply unless on development Jumping Pound is a better field than Mr. Davis estimates, in which case part of the additional requirement might come from there. Subject to that qualification, however, on the evidence submitted the only sources from which Canadian Western's requirements over the period of thirty years, not to say fifty years, can be met, are Pincher Creek and Pakowki Lake, or Pincher Creek alone. On any figures submitted so far the Pakowki Lake area does not hold sufficient reserves for the purpose. In the result the Canadian Western Company as at present advised would seem to require directly or indirectly the Pincher Creek gas."

The City of Calgary through its counsel emphasized that protection should be given to the consumers of natural gas within and adjacent to the City of Calgary and tributary to the system of the Canadian Western Natural Gas Company by way of a proven reserve of pipe line gas available to such consumers and deliverable in both volume and demand for a period of fifty years. The counsel also stressed the importance of protection in regard to price, which he considered almost as important as protection to supply. He submitted that while the Conservation Board had no power to fix prices, it could create conditions which might inevitably result in increased price. He considered that this might be remedied by attaching conditions to any export permit to safeguard prices to local consumers, but he offered no recommendations as to what these conditions might be.

Counsel for the City of Calgary also stated that protection of Alberta consumers as to reserves can only be given in conjunction with protection as to price if allocation of reserves for local consumption is made by whole areas rather than by percentages or portions of gas within any area. He was also concerned in the share of gas production from a field between local consumption and an export market, particularly if the local market was to be served late in the life of a field on the grounds that the low pressure residual gas is the expensive gas—as compared with the gas produced initially. This might be the case, but if a reasonably accurate reserve can be estimated for a field and the capital costs are properly depreciated on a unit cost basis the situation need not arise.

Both counsel for the Canadian Western Utilities and the City of Calgary consider that Pincher Creek should be held in reserve for the City of Calgary, even though Mr. Davis did not consider it attractive from an economic point of view. Counsel for the City of Calgary did not oppose the export of gas from the Pakowki Lake fields to Montana even though those fields might be useful in enabling Pincher Creek to produce at a reasonably steady rate. It might well prove eventually that a division of a steady production load between the Calgary market and an export market may be beneficial to the Calgary system, particularly if peak loads can be provided from a dry gas field reasonably close to the system.

The problem of protecting the consumers of the major utility systems raises the following issues:

1. How long should consumers of the two major systems be protected either by acquisition by the utility companies or allocation of proven reserves?
2. Should the consumer be required to pay for this protection? If so, then it would appear to follow that the utility companies should acquire sufficient reserves to maintain supply and deliverability for the desired period of protection.

3. If the consumer is not to pay for long-term protection, it would seem to follow that the cost would have to be borne by the owners and operators of the gas reserves which are allocated for consumer protection. These reserves in effect would be frozen until such time as the utility systems require them to meet consumer demand or are declared surplus if more attractive reserves from their point of view are discovered in the meantime.

4. Is it in the best interests of the consumer that he be protected for a long period of time against all eventualities if he has to pay for this protection? It may be that as a result of gas strikes, potential gas areas may be established in the areas adjacent to a utility and that it would be in the interests of the consumer to "take a chance" on these reserves being proved up either by the utility itself or by other people as it becomes necessary to acquire additional reserves for the system.

   Protection could be considered an insurance and there has to be a reasonable balance between risk and cost. It would appear that protection for a period of from 20 to 30 years would be reasonable. Among the many factors affecting the risk, two of the major ones are:

   (a) the available reserves and the prospects for gas development in areas reasonably close to the utility system; and

   (b) accessibility to the utility companies of more distant reserves brought within economic reach through the construction of main transmission lines which might follow further development.

5. Is it in the best interests of the Province as a whole that Established Reserves should be frozen until such time as the two major distributing systems decide whether or not they require these reserves on the premise that they might be able to obtain more suitable reserves or further supplies of oil-field gas should additional discoveries be made within economic reach of their system?

   This would appear to have the effect of protecting the interests of the consumers of the two major systems at the expense of the balance of the population in the Province. It is apparent that unless some satisfactory scheme can be worked out whereby it can be shown that additional markets will be made available in the near future for gas there will be little incentive for gas development. As a result, other communities may be deprived of a chance to obtain gas and to participate in the general prosperity which increased discoveries of wet and dry gas may bring by way of increased industrial expansion, with corresponding increase in population, and the creation of additional markets for their products.

The Board suggests that the Government should give consideration to the advisability of requiring utility systems to have sufficient reserves of gas held under their control or under contract to ensure consumer protection over a reasonable period of years.

While it is realized that the Alberta consumer must be protected both in regard to adequacy of reserves and price, and that the distributing systems should be able to obtain gas at the lowest possible cost, the Board does not believe this should be done at the expense of having Established Reserves remain idle without recompense to those who have developed them. In other words, it seems only reasonable that the consumers should have to pay for development of reserves to afford them the desired protection.

The Board appreciates the difficulties which might arise if the utility companies contract for gas from a dry gas field and an oil-gas field is discovered within economic distance of the utility market. The Board might find itself in the position of having to require the utility system first to take the oil-field gas rather than to tolerate waste or involve operators in an uneconomic re-pressuring scheme. If such a course were followed some form of compensation would have to be made to the operator of the dry gas field. This might be done by paying him a premium on the gas he was permitted to supply the market to meet peaks—with a corresponding reduction in the price of oil-field gas. As an alternative, if the dry gas field is used only to meet peak demands and this production is not sufficient to make the project economic, the owner or operator of the dry gas field might be entitled to a share of the market, even though he might contribute only to its peak requirements, and the unproduced gas could be considered on a stored reserve basis to be produced at a later date—similar to the plan now in effect in Turner Valley.

Alternative Sources of Fuel Energy

Alberta is a reservoir of fuel energy with its large reserves of coal, oil and gas, and it has a great responsibility not only to the people of the Province but to our neighbouring provinces and to Canada in ensuring that these resources are developed for the greatest common good.

A considerable amount of research work is now being done in relation to the utilization of the various fuels for energy and other purposes. It is quite possible, and something that we should look forward to, that new and economically more attractive methods will be found for utilizing Alberta's large coal reserves to provide fuel for power development and both fuel and raw materials for industry. It should also be kept in mind that the development of atomic energy may well progress to the stage within the next fifteen or twenty years that it will be used extensively in industry and for general power generation.

In the light of Alberta's resources, it is the belief of the Board that the Province should continue and expand its scientific research into the utilization and development of gas, oil and coal for energy and other purposes.

Grid System

During the hearings of the applications, Alberta Interfield Gas Lines Limited advocated the development of an integrated Province-wide gas gathering system or grid. It was submitted that an integrated grid system could result in the elimination of unnecessary facilities, the more effective utilization of dry gas fields, additional assurance for continuity of supply and other advantages both to the producers and the consumers of the Province.

On the other hand, it was pointed out that the immediate establishment of such a system might not be economic and that the orderly growth of the present lines and systems to meet requirements as they develop might be more practical from the point of view of distribution of gas both to internal and export markets.

While recognizing the desirable features of such an integrated system the Board is not at this time prepared to state whether in its opinion the scheme is necessarily economical and practical.

VIII RECOMMENDATIONS AND CONCLUSIONS

1. On the basis of present evidence and the Board's consideration thereof, the Board finds the present established reserves of gas as at January 1st, 1951, to be:

	Within Economic Reach MMMcf	Beyond Economic Reach MMMcf
General use (including the two major utility systems)	4,057	219
Reserved for local use	382	
Total	4,439	219

2. The Board concurs in the unanimous evidence of geologists and others to the effect that the vast sedimentary deposits underlying the Province offer great possibilities for the development of gas reserves.

3. The Board has no doubt that the development of gas reserves has been hindered by the lack of incentive caused by:
   (a) Provincial Government restrictions on export,
   (b) the lack of a large internal market.

4. The Board believes that while the present system of disposing of Crown lands and the establishment of Crown reserves is fair and equitable in so far as oil development is concerned, it is not well suited for gas exploration and development where larger blocks of land are necessary in order to make development of reserves attractive. It recommends that the Government favourably consider making "gas only" rights in specific zones available for exploration and lease in large blocks on a drilling performance basis.

5. In view of the most favourable prospects of the Province for the discovery of additional extensive gas reserves and in view of the possibility of the development of alternative forms of fuel and energy, the Board believes that the Province will be adequately protected if sufficient reserves of pipe line gas are provided to maintain the supply and deliverability for thirty years.

6. The Board does not believe the best interests of the Province as a whole would be served by requiring more than thirty years' protection since this would have a continuing stifling effect upon the development of the gas and related industries.

7. The Board estimates the Province's requirements for the 30-year period—1951-1980—as 3,059.9 billion cubic feet made up as follows:

Domestic MMMcf	Commercial MMMcf	Industrial MMMcf	Total MMMcf
873.7	751.7	1434.5	3,059.9

8. The Board considers that in order to meet the deliverability of the aforementioned requirements that established reserves of the order of four and one-half trillion cubic feet are required.

9. The Board finds that, taking into consideration:
   (a) established reserves as estimated by the Board,
   (b) requirements of the Province for thirty years as estimated by the Board,
   (c) deliverability of gas to meet the thirty-year requirements of the Province as estimated by the Board,
   (d) requirements of the various applicants who have been heard by the Board,
   (e) the policy of the Government with respect to Canadian preference;

   it cannot at this time recommend the granting of a permit to remove gas or cause it to be removed from the Province to any of the applicants.

10. The Board believes that the natural unfavourable load factor characteristics of the provincial market could and should be alleviated in the future through the further development of storage projects.

11. The Board recommends that the following applications be continued until September 4th, 1951:

Westcoast Transmission Company Limited and Westcoast Transmission Company Ltd.

Northwest Natural Gas Company and Albera Natural Gas Grid Limited,

Western Pipe Lines,

Prairie Pipe Lines Limited,

McColl-Frontenac Oil Company Limited and Union Oil Company of California;

and further recommends that upon application to the Board of any of the aforesaid applicants to have its case re-opened, prior to September 4th, 1951, because of new evidence it wishes to adduce, the Board, upon being satisfied that such evidence warrants it, may fix a date prior to September 4th, 1951, to hear the evidence and reconsider the application.

12. The Board believes it is in the best interests of the Province to encourage gas development, and that if as a result of more intensive exploration and the establishment of further gas reserves, a successful trend is indicated, the Board would be prepared to consider recommending the granting of an export permit based upon a lesser degree of provincial protection.

13. While the Board does not recommend export at this time, it believes that with the further development of established reserves and the development of promising strikes, the situation could change rapidly whereby export could be permitted. This, in the opinion of the Board, would be in the best interests of the Province and of Canada.

Respectfully submitted,

I. N. McKINNON,
Chairman.

D. P. GOODALL,
Deputy Chairman.

G. W. GOVIER,
Board Member.

Dated at Edmonton, Alberta,
this 20th day of January, 1951.

APPENDIX 1

Applications Pending for Permission to Remove Gas or Cause it to be Removed from the Province

Applicant	Date of Application	Sittings	Scope of Evidence
Westcoast Transmission Company Limited (Canadian and Provincial Companies)	Oct. 17, 1949	Dec. 10, 1949 Dec. 19, 1949 (adjournment) Jan. 30-Feb. 17, 1950 Apr. 11-Apr. 13, 1950 June 12, 1950 (adjournment)	Reserves Deliverability Requirements within the Province of Alberta Market requirements of pipe line outside Alberta Route proposed: Cost of construction
Northwest Natural Gas Company and Alberta Natural Gas Grid Limited	Aug. 18, 1949	Nov. 28, 1949 Dec. 19, 1949 (adjournment) Apr. 17, 1950 (adjournment) May 29-June 9, 1950	Reserves Deliverability Requirements within the Province of Alberta Market requirements of pipe line outside Alberta Route proposed: Cost of construction
Western Pipe Lines	Feb. 14, 1950	June 19, 1950 Sept. 19, 1950 Sept. 25-Sept. 28, 1950	Reserves Deliverability Requirements within the Province
*Prairie Pipe Lines Limited	April, 1950 Sept. 1950 (amended)	Oct. 10-Oct. 12, 1950	Reserves Deliverability Requirements within the Province
McColl-Frontenac Oil Company Limited and Union Oil Company of California	Aug. 2, 1950	Dec. 4, 1950	Reserves Deliverability Requirements within the Province Market requirements outside of Alberta Route: Cost of construction
Canadian Delhi Oil Limited	Sep. 29, 1950	Jan. 8, 1951	

*Prairie Pipe Lines has been taken over by Pacific Northwest Pipeline Corporation and its application has been amended accordingly.

In addition to the sittings listed, all applicants with the exception of Canadian Delhi Oil Limited were represented and gave evidence at the Joint Hearing October 30th - November 3rd; November 6th to November 10th.

APPENDIX 2

MILNER, STEER, DYDE, POIRIER, MARTLAND & LAYTON

Edmonton, Alberta,
August 29th, 1950.

The Chairman,
The Petroleum and Natural Gas Conservation Board,

Dear Sir:

The writer acts on behalf of Western Pipe Lines which has been represented at the hearing before the Board of the application of Westcoast Transmission Company Limited and Northwest Natural Gas Company.

We are somewhat concerned over the amount of time which has been devoted to the presentation and cross-examination of evidence dealing with pipe line routes, design and cost. While we realize that the Board requires such evidence, nonetheless the Board of Transport Commissioners must authorize the route and construction of any inter-provincial pipe line. It seems to us, therefore, that the proper place for a detailed examination of these matters is before the Board of Transport Commissioners. Moreover, if gas is to be exported out of Canada, the Dominion Government, through the Department of Trade and Commerce, will have to grant a permit authorizing such export.

We would respectfully suggest that it would be in the interest of all applicants and of the Board to curtail the presentation and the cross-examination of evidence on routes, pipe line design and cost. We would also recommend that the Board, after hearing all pertinent evidence, might determine the existence or otherwise of an exportable surplus of natural gas and, if there should be a surplus, determine with the approval of the Government of Alberta, the conditions and provisos necessary to protect the interests of the people of Alberta and of Canada. The choice of the pipe line route should, in our respectful submission, be left to the Board of Transport Commissioners.

The Petroleum and Natural Gas Conservation Board and the Provincial Government, having thus determined the conditions under which an export permit might be issued, could let it be known that such a permit would issue after the Board of Transport Commissioners had approved the route and the Department of Trade and Commerce had authorized export of natural gas, if outside of Canada.

We would also respectfully suggest that, for the reasons outlined above, the Board might consider the desirability, with respect to its further proceedings, of conducting a joint hearing, in respect of all applicants before it, with regard to the question of the existence or otherwise of an exportable surplus of natural gas. Our idea is that all further evidence of any of the applicants in connection with this issue might be adduced at the one hearing, together with any other evidence on that point which any interested party might wish to present or which the Board might consider it desirable to hear.

We would respectfully request the Board's permission to submit an application on behalf of Western Pipe Lines to the Board, covering both the above points, when the hearings resume on September 25th.

We are sending a copy of this letter to the Honourable N. E. Tanner, Minister of Mines and Minerals.

Yours very truly,

Milner, Steer, Dyde, Poirier, Martland & Layton
per: "R. Martland"

APPENDIX 3

THE WESTERN CANADA PETROLEUM ASSOCIATION

Calgary, Alberta,
September 20th, 1950.

Chairman,
The Petroleum and Natural Gas Conservation Board,
514-11th Ave. West,
Calgary, Alberta.

Dear Sir:

At a recent meeting, the directors of this Association adopted unanimously the following resolution:

"That The Petroleum and Natural Gas Conservation Board be requested to come to a decision at the earliest possible date as to whether the gas requirements of Alberta and the reserves of the Province are such as to warrant the export of natural gas; and that in order to expedite such decision, they confine their enquiries for the present to these questions only."

In submitting this resolution, the directors wish to make it clear that they are in no way suggesting that the Conservation Board is to be criticized for the procedure adopted in the hearings up to date. They realize that the procedure followed was that desired by most of the applicants, whose views were entitled to consideration.

However, recent developments have in the opinion of the directors, made it essential that the preliminary question as to the availability in Alberta of gas for export, be determined as soon as possible, leaving all other questions for later determination.

Respectfully yours,
G. W. Auxier,
Executive Vice-President.

GWA:A

APPENDIX 4

DEPARTMENT OF MINES AND MINERALS

Edmonton, Alberta,
September 23rd, 1950.

I. N. McKinnon, Esq.,
Chairman,
The Petroleum and Natural Gas Conservation Board,
514-11th Ave. West,
Calgary, Alberta.

Dear Mr. McKinnon:

The attached letter from the Right Honourable C. D. Howe is self-explanatory.

Owing to the urgency expressed therein, I have been directed by the Executive Council to ask that your Board do all possible to facilitate your hearings so as to determine the amount of proven reserves of deliverable natural gas within the Province and the foreseeable needs of the Province for domestic and industrial use; and, further, to advise as to whether or not and to what extent there is a surplus which might be available for sale outside the Province.

I have advised Mr. Howe of this action and explained to him the policy of this Government as expressed by Premier Manning on several occasions, and particularly as expressed by him in his Budget Address this year, which is as follows:

"The Government's first and foremost responsibility is to protect the interest and welfare of the people of this Province, and we are determined to carry out this responsibility to the best of our ability. To this end, no application for the export of natural gas will be given favourable consideration until such time as the Government is satisfied beyond question that under sound conservation and proration practices there are sufficient gas reserves to meet the present and future domestic and industrial requirements of this Province. When fully satisfied that this surplus exists over and above these requirements, sufficient to justify export under sound conservation and proration practices, the Government will approve the export of such surplus, with each application being considered on its own merits and in the light of all prevailing circumstances. Furthermore, it will be a condition of any export permit that Canadian requirements must be given first priority."

Taking into consideration the prevailing circumstances, we shall appreciate being advised of your findings at an early date, so that we might advise Mr. Howe accordingly.

Yours very truly,
N. E. Tanner,
Minister.

APPENDIX 5

DEPARTMENT OF TRADE AND COMMERCE

Ottawa, Canada,
September 16th, 1950.

Hon. N. E. Tanner,
Minister,
Department of Mines and Minerals,
Edmonton, Alberta.

Dear Mr. Tanner:

I have recently been advised by the Chief of the International Programme of the United States Munitions Board that the Board is seriously concerned about the lack of fuel in the Pacific Northwest section of the United States, where the wartime industrial development, together with diversion of normal oil supplies to the Far East, has seriously accentuated the scarcity.

It is suggested that the availability of large supplies of natural gas in the Province of Alberta is one source from which the scarcity of fuel and power in the Pacific Northwest could be alleviated. I am asked the question whether these supplies can be made available.

The letter indicates that if the supplies are not available, immediate steps will be taken to supply the area from Texas sources of natural gas. You are aware that an application has recently been filed with the Federal Power Commission of the U.S.A. for permit for a pipeline from Texas to the Pacific Northwest.

This Government is in the position that we cannot answer the question until Alberta decides whether gas from that Province will be made available for export outside the Province. There would seem to be great urgency for a decision one way or another. I sincerely hope that it will be forthcoming shortly as pressure from the Munitions Board will certainly be a decisive factor in authorizing the granting of the franchise from Texas.

I see little prospect of a line being built from Alberta to the Canadian Northwest unless that line can be extended from Vancouver southward to serve the Pacific Coast cities.

Yours sincerely,
(Sgd.) C. D. Howe.

EDMONTON, CANADA:
PRINTED BY A. SHNITKA, KING'S PRINTER
1951